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Software Requirements Specification for Management for Grid Control

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Abstract

This Software Requirements Specification defines the functions of a simulation power grid model. The model defines grid control functions that focus on real-time control and related communication of information among entities that share the operation of the power grid. Deregulation of the power markets necessitates increased communications among entities who have economic motivation to restrict access to important information from other market participants. New power market concepts will impact how planning and real-time control are performed. The simulation power grid model provides the tool for investigating issues of distributed computing, data sharing, data access, communication system capacity, and communications reliability. The model enables researchers to develop intelligent distributed control agents for managing Area Control Error and transmission security. The software requirements specification is defined using a subset of the Unified Modeling Language, a class diagram describing all of the objects along with their attributes, methods, and some modified use cases.

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions on behalf of the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Power Technologies of the U.S. Department of Energy under Contract No. DE-AC04-94AL85000.

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1. Introduction

This document is part of the Information Management for Grid Control project funded by Consortium for Electric Reliability Technology Solutions (CERTS). [CERTS-Proposal] This document covers the requirements for the Intelligent Agent (IA) team.

"The initial focus of this research is understanding requirements for and developing intelligent distributed control agents to manage Area Control Error (ACE) and transmission security. The industry must develop a way to balance the conflicting goals of open markets enabled by wide-spread access to information with security from information system intrusions which would introduce bogus data or shut down computers due to data overload or malicious software viruses. The next steps are to research information flows in detail and to identify necessary information processing functions at each node in the control network." [CERTS-OEFR]

Application of fault-tolerant computing techniques to the distributed real-time control of the power grid will increase system reliability and enable new concepts for operation of open power markets.

Many of the concepts developed in this project may apply to real-time control of microgrids, an area being researched in another CERTS project. Microgrids are a particularly attractive application because the economics dictate that the real-time control be completely automated. While the distances between entities in a microgrid are smaller, many of the same requirements for distributed control exist.

1.1 Purpose

This Software Requirements Specification (SRS) describes the functions to be provided by the software product. This SRS does not prescribe how the functions are to be implemented and does not define distributed computing approaches, data structures, communication protocols, or other implementation features.

The purpose of this SRS is to serve as a statement of understanding between the users of the proposed product and the software developers of the product.

1.2 Scope

This document defines the functions of a simulation power grid model. It defines the requirements on the software product and bounds the portion of the Electric Power Grid problem to which IA technology will be applied. The simulation power grid model is based on the IEEE Reliability Test System – 1996. It defines grid control functions that focus on real-time control and related communication of information among the entities that share the operation of the power grid. With deregulation of the power markets has come the need to increase communications among entities and where there is economic motivation to restrict access to important information from market participants. New power market concepts will impact how planning and real-time control are performed. The simulation power grid model provides the tool for investigating issues of distributed computing, data sharing, data access, communication system capacity, and communications reliability.

1.3 Software Modeling

The software models in this document are a subset of the Unified Modeling Language (UML), a class diagram describing all of the objects along with their attributes and methods, and some modified use cases. The use cases are modified because the software developers of the intelligent agents needed a functional decomposition (a.k.a. data flow diagram) of the model. Therefore, the modified use case diagrams are an adaptation of the tool to show functional decomposition.

The UML model is available in web-site format.

1.4 Acronyms and Abbreviations

This section contains definitions of technical terms and phrases used in this document. Acronyms and abbreviations also appear in this section.

1.4.1 Intelligent Agent Terms

IA - Intelligent Agent.
PAS – Prototype Agent System

1.4.2 Power Grid Terms

ACE - Area Control Error.
AGC - Automatic Generation Control.
ANLS – Adjusted Native Load Schedule.
CERTS - Consortium for Electric Reliability Technology Solutions.
CA - Control Area(s). "CONTROL AREA. An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its INTERCHANGE SCHEDULE with other CONTROL AREAS and contributes to frequency regulation of the INTERCONNECTION." [NERC-Term]
CAO – Control Area Operator.
FERC - Federal Energy Regulatory Commission.
G - Generator(s).
GM - Grid Model.
IOS - Interconnected Operating Services [NERC-IOS].
IMGC - Information Management for Grid Control.
Inadvertent Interchange. The difference between the Control Area's net actual interchange and Net Scheduled Interchange.
Interchange Schedules. The schedules between Generators in one Control Area and Load-Serving Entities within another Control Area are known as interchange schedules. Interchange schedules start in other Control Areas, pass through transmission tie lines, and terminate in the Control Area containing the loads, called the sink Control Area. Interchange schedules are not specified as to which substation bus they originate or terminate.
LSE - Load-Serving Entity(ies).
MTMLF – Minute-to-Minute Load Forecast.
NERC - North American Electric Reliability Council. The NERC web page is at www.nerc.com.
NSI – Net Scheduled Interchange. The net of all Interchange Schedules with all adjacent Control Areas. [NERC-Terms]
PA – Power flow Analysis.
SC - Security Coordinator(s). "SECURITY COORDINATOR. An entity that provides the security assessment and emergency operations coordination for a group of CONTROL AREAs. SECURITY COORDINATORS must not participate in the wholesale or retail merchant functions." [NERC-Terms]
Schedules serving Native Loads. The schedules between Generators and Load-Serving Entities that are each within a Control Area are known as schedules serving native loads or just schedules. Schedules serving native loads start and terminate at the appropriate substation buses in a Control Area.
SCADA – Supervisory Control and Data Acquisition. A system of remote control and telemetry used to monitor and control the transmission system. [NERC-Terms]
TSP - Transmission Service Provider. "TRANSMISSION PROVIDER. As defined by FERC, the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff. As used in the NERC Policies: Any entity that provides Transmission Service." [NERC-Term]

1.4.3 Other Terms

DFD - Data Flow Diagram.
N/A – Not Applicable
SRS - Software Requirements Specification.
Surety - Surety is a combination of safety, security, use-control, and reliability.
TBD - To Be Determined.
UCI – Unclassified Controlled Information.
UML - Unified Modeling Language.

1.5 References

1.5.1 Project and Related Documents

[CERTS-Proposal] *CERTS Project Proposal Information Management for Grid Control*, Sandia National Laboratories, Douglas Smathers and Abbas Akhil, Washington State University, Anjan Bose, February 4, 2000.

[CERTS-OEFR] Consortium for Electric Reliability Technology Solutions Operating Environment and Functional Requirements for Intelligent Distributed Control in the Electric Power Grid, Sandia National Laboratories, Douglas Smathers and Abbas Akhil, February 10, 2000.

[IA-IDCEPG] *Agent Concept for Intelligent Distributed Coordination in the Electric Power Grid,* Sandia National Laboratories, Douglas Smathers and Steven Goldsmith, March 20, 2000.

[IEEE-RTS-86] *The IEEE Reliability Test System - Extensions to and Evaluation of the Generating System*, R. N. Allen, R. Billinton, and N.M.K. Abdel-Gawad, IEEE Transactions on Power Systems, Vol. PWRS-1, No. 4, November, 1986.

[IEEE-RTS-96] The Reliability Test System – 1996. A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee, IEEE Transactions on Power Systems, Vol. 14, No. 3, August 1999.

[NERC-ACE] *NERC Operating Manual- Appendix 1A - The Area Control Error (ACE) Equation*, North American Electric Reliability Council, December 3, 1996. www.nerc.com/~oc/opermanl.html

[NERC-Map] *NERC Operating Manual - NERC Regional Map*, North American Electric Reliability Council, 1998. www.nerc.com/~oc/opermanl.html.

[NERC-IOS] *NERC Operating Manual -Draft Policy 10 - IOS,* North American Electric Reliability Council, December 15, 1999. www.nerc.com/~oc/opermanl.html

[NERC-TERMS] *NERC Operating Manual - Terms Used in Manual*, North American Electric Reliability Council, February 15, 2000. www.nerc.com/~oc/opermanl.html.

[NSTAC] National Security Telecommunications Advisory Committee, Information Assurance Task Force, Electric Power Risk Assessment. http://www.aci.net/kalliste/electric.htm

[Schneider, 1997] Schneider, F.B. "Towards Fault-Tolerant and Secure Agentry" in Mavronicolas, M. and Tsigas, Ph. Eds, *Lecture Notes in Computer Science, Vol. 1320: Distributed Algorithms, Proceedings of 11th International Workshop, WDAG'97*. Springer, Saarbrucken, Germany, September 1997, pages 1-14.

[Stevenson, 1982] Stevenson, William D. *Elements of Power system Analysis (4th Edition).* McGraw-Hill International Book Company, Singapore: 1982.

[Wood, 1996] Wood, Allan J. and Wollenberg, Bruce F. *Power Generation Operation and Control (2nd edition).* John Wiley & Sons Inc., New York: 1996.

1.5.2 Software Engineering Related Documents

[SEQIT-SDMHCS] *Software Development Methodology for High Consequence Systems*, Software Engineering Quality Improvement Team, Sandia National Laboratories, Released Version 3.0, August 1997.

[SEQIT-DocID-Project] *Project Document Identification Guideline*, Software Engineering Quality Improvement Team, Sandia National Laboratories, Released Version 1.0, March 18, 1999.

1.6 Document Overview

This document is formatted based on the principles in the IEEE Guide to Software Requirements Specifications, ANSI/IEEE Standard 829-1983. This standard is a well-established guide to software requirements specifications in the computer software engineering community.

Chapter one contains an introduction to this document.

Throughout this document any reference document abbreviation inside square brackets (e.g. [NSTAC]) indicates a reference to the documents listed in Section 1.5.

Chapter two contains a high level description of the software functionality for the simulation power grid model. Also in chapter two is a description of the Prototype Agent System including communications schemata and state descriptions for real-time operations. There is also a discussion of techniques to detect a malfunctioning agent, how to spawn a new agent, how to re-allocate an agent's tasks, and how to approach contingency planning in the agent system.

Chapter three contains the specific requirements the software must meet. Requirements in this document are numbered. The numbering scheme has the document number or project designation, followed by a ".", followed by the requirement number, followed by a ".", and followed by the version number of the requirement (e.g. IMGC.031.001)(i.e.<project/document-nick-name>.<requirement-number>.<requirement-version-number>). The version number is the version of the requirement, not the version of the requirements document.

1.6.1.1.1 Each requirement has an attribute bar with it that looks like the following:

Requirement #: IMGC.333.005	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 9/5/1997	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 10/15/1997	☐ IA	☐ Accepted	☒ None	☐ High

The "Requirement #" field contains the requirement number. Once a requirement number is assigned to a requirement, only the version portion of the number is changed.

The "Date introduced:" field contains the date that the requirement was first introduced (i.e. typed) into the SRS.

The "Date of last change:" field contains the date that the requirement was last changed. The first time the requirement is typed in, the "Date of last change:" will be equal to the "Date introduced:".

The "Area:" field defines to whether the requirement is applicable more to the ACE or IA.

- "ACE" covers Area Control Error and power grid specific issues.
- "IA" covers Intelligent Agent specific issues.

The "Status:" field defines the status of the requirement. The status is either draft or accepted.

- "Draft" means the requirement is in draft form. A newly typed in requirement is usually a draft, unless the content has already been reviewed.
- "Accepted" means the requirement has been accepted. A requirement shall be accepted by an SRS review.

The "Classification:" field defines the level of classification. This field is included to let us know what is UCI and what is unlimited release.[Note: Only unlimited release information can be used in this version of the specification.]

The "Surety rating" defines which requirements are surety related. Surety relates to safety, security, reliability, and if the system is under positive control. The system hazard analysis, if done, will directly impact this field for each requirement.

2. Overall Description

The following sections describe the high level view of the system and establish its context. These sections do not state specific requirements but make the specific requirements easier to understand.

2.1 Product Perspective

2.1.1 Physical System Context - Electric Power Grid

The electric power grid, operated under policies and standards established by NERC, is divided into several regional reliability councils as shown in Figure 1. All regions, except the WSCC and ERCOT, are in synchronous operation.

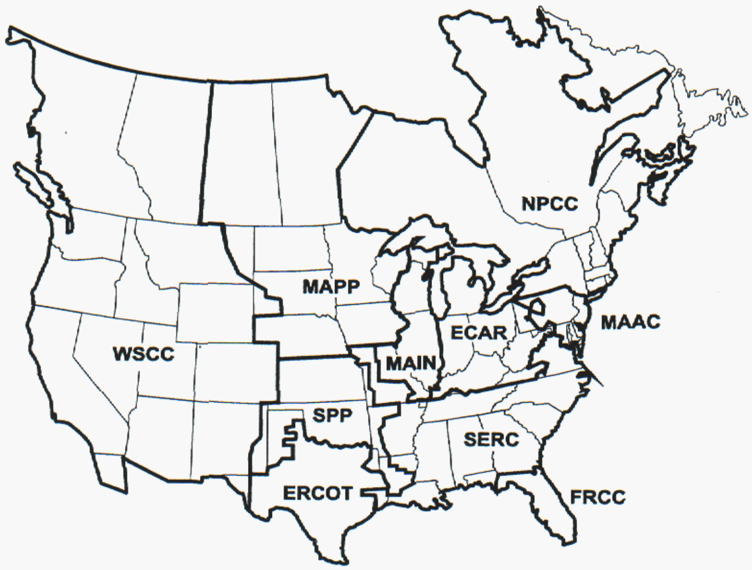


Figure 1 - NERC Map of regions [NERC-Map]

The Acronyms for the regions are as follows:

ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAAC - Mid-Atlantic Area Council
MAPP - Mid-Continent Area Power Pool
MAIN - Mid-America Interconnected Network
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council

At a very high level of abstraction, the power grid is a set of interconnected areas. The main components of the power grid are generation of electric power, transmission of the electric power, distribution of the transmitted power to the users, and the loads that the users create. Examples of these components are shown in Figure 2. A Bulk Electric System includes generation, transmission and related equipment that are interconnected with transmission lines.

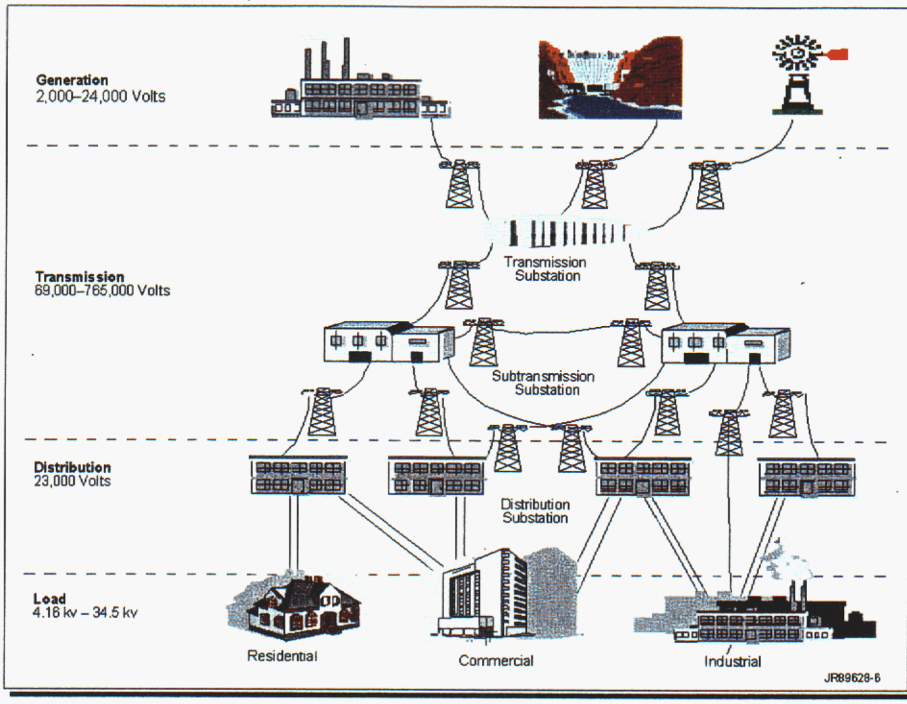


Figure 2 - Major components of an electric power system [NSTAC]

The electric power grid in North America is divided into three Bulk Electric System networks called Interconnections. The Western Interconnection is managed by the WSCC. The ERCOT Interconnection is managed by ERCOT. The Eastern Interconnection is managed jointly by the eight other NERC regional reliability councils. Each Interconnection is organized into one or more Security Areas. Each Security area has a Security Coordinator who is responsible for security assessment and emergency operations coordination for a group of Control Areas. Each Security Area contains multiple Control Areas which contain generation, transmission, and distribution components. A partial summary is diagramed in Figure 3.

Collections of equipment and computer networks allow communication of important data items. Figure 4 shows an example layout of a computer network in a control center.

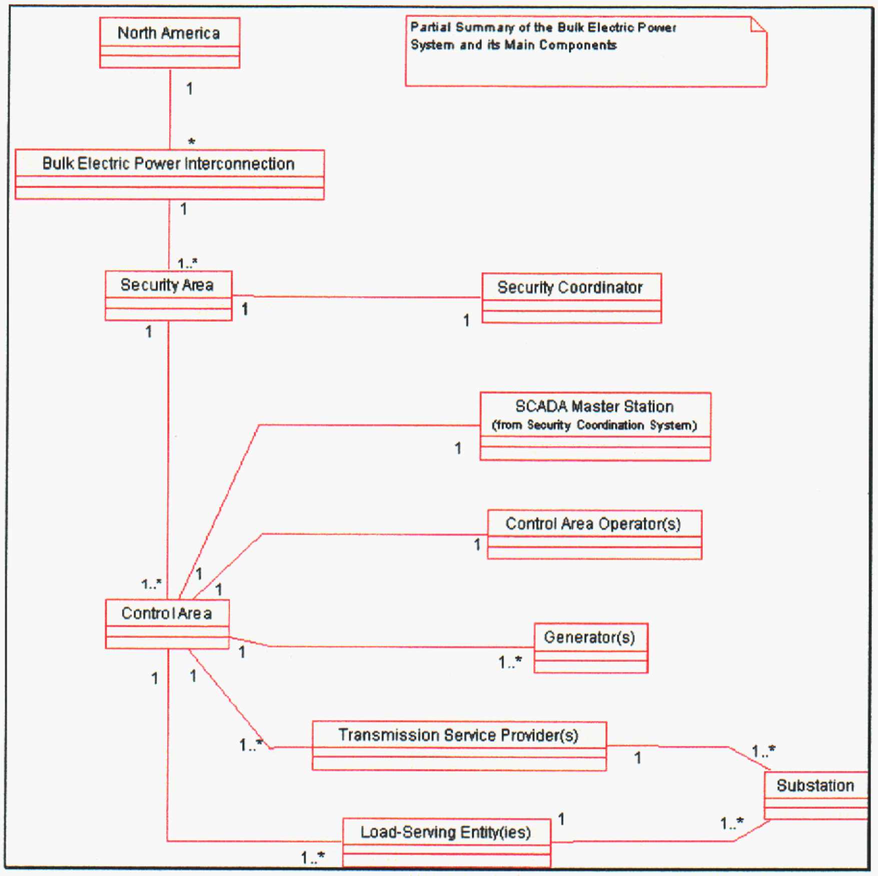


Figure 3 - Partial Summary of Bulk Electric System

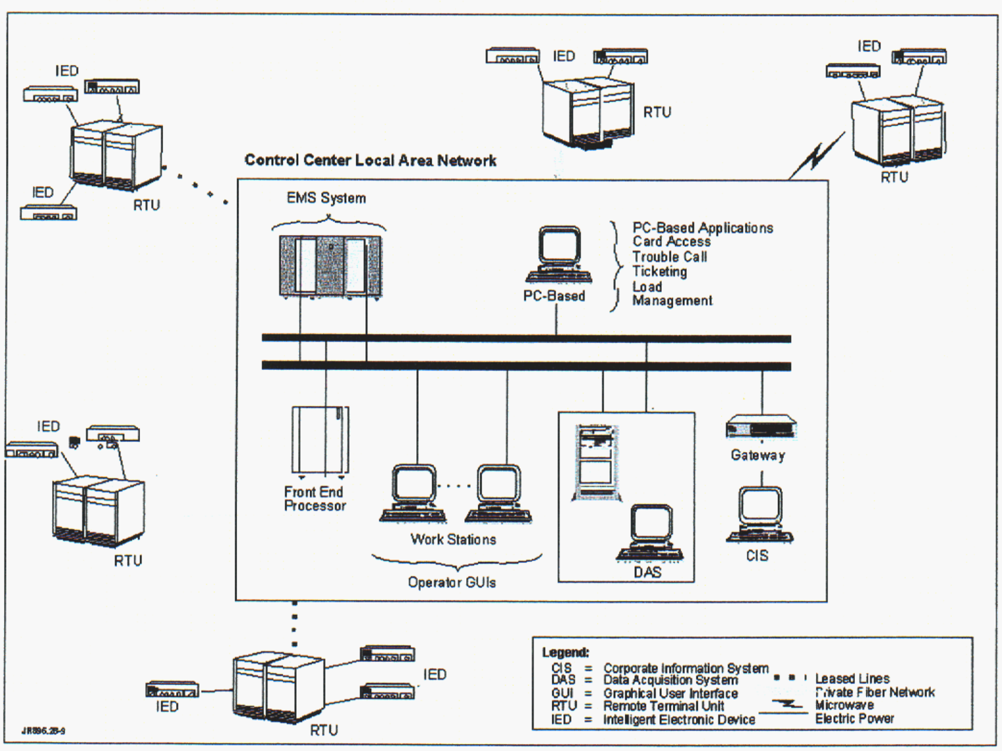


Figure 4 - An example Control Center Computer Network Layout [NSTAC]

2.1.2 Physical System Context - Real-Time Management of ACE

The NERC operating manual defines the importance of ACE as follows:

> " It is the obligation of each control area to fulfill its commitment to the Interconnection and not burden the other control areas in the Interconnection. Each control area should minimize their effect on other control areas within the Interconnection. Any errors incurred because of generation, load or schedule variations or because of Jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept between the involved parties and not passed to the Interconnection. In addition, this ACE should NOT include any offsets (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.)" [NERC-ACE]

Figure 5 show an example of a typical day. The jagged line is the actual load and the nice step function line is the scheduled load which is forecast and planned for. The difference between the two lines is accommodated by the Interconnected Operations Services (IOS). IOS are the fundamental physical capabilities or "building blocks", supplied by generation or load resources, needed to maintain the reliability of interconnected power systems in North America. NERC draft Policy 10 defines five types of IOS. These types of services parallel the definitions of ancillary services in FERC orders. For simplicity, this SRS only considers the IOS of regulation and contingency reserves.

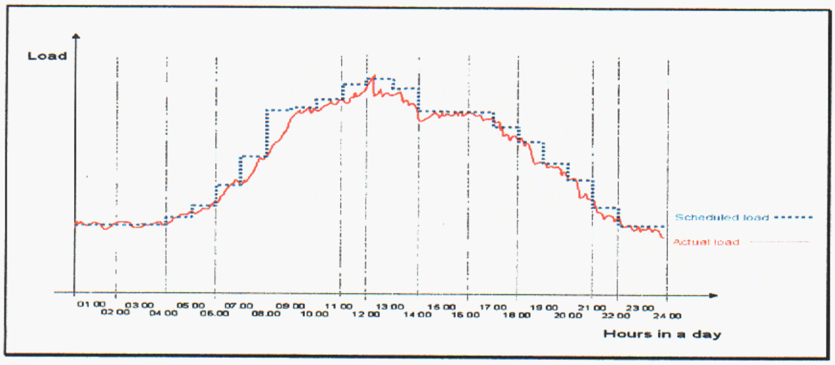


Figure 5 - Example of Scheduled Load vs. Actual Load for a typical day

2.1.3 Simulation Power Grid Model

The entities, their responsibilities, and other nomenclature roughly follow the documentation in the NERC Operating Manual, Draft NERC Policy 10 (IOS), Basic Operating Functions and Responsibilities: A White Paper by the Control Area Criteria Task Force, and Tagging Essentials: the Basics of Tagging. There are conflicts in nomenclature among the latest drafts of these documents. The Load-Serving Entities perform marketing and scheduling functions that do not appear in the current software model. A lot of the details are undergoing significant changes so predicting the future forms of entities and nomenclature is not possible at this time.

2.1.3.1 Simulation power grid entities

The simulation power grid model contains five principle entities. This section defines the functions that each of these entities will perform in the simulation that will be used to test the intelligent agents that operate in each entity. The simulation power grid model consists of two phases. The planning phase establishes the power grid configuration, generator availability, load forecasts and interchange schedules that match generation resources to load forecasts. The planning phase is performed without a time measure so it only represents the way the model establishes the parameters for real-time grid control operations. The second phase is the real-time operations phase. This phase simulates activities at the bulk electric system level. Real-time operations are modeled in a greatly simplified way to focus on information management needed to implement interchange schedules and manage generation-load balancing during routine operating conditions. Once per minute each Control Area performs a calculation which simulates the frequency response of generator units to generation-load imbalance. The result is a command to adjust generator unit output which we call Automatic Generation Control (AGC) dispatch. Each Control Area cannot determine the actual power flows between Control Areas separately. Every ten minutes a DC power flow analysis is done for the entire grid to determine the Inadvertent Interchange between Control Areas. The Inadvertent Interchange values are accumulated and reported every hour. A value with some of the properties of Area Control Error (ACE) is calculated every ten minutes. In addition, each Control Area redispatches generation every ten minutes to correct the generation-load imbalance and zero the AGC dispatch. The software model only includes a limited number of features of the actual power grid in order to allow the model to be developed in the time available. Additional features can be added at a later time. Daily and seasonal load profiles and random fluctuations of load are used to introduce dynamic elements into the simulations.

The simulation power grid model incorporates one Security Coordinator, three Control Areas, four Generator Entities, one Transmission Service Provider, and twelve Load-Serving Entities. Specifically, the software model does not incorporate the market mechanisms that set prices or determine bilateral transactions among the for-profit market entities. Neither are transmission reservations or the electronic tagging process modeled in detail. Instead, Control Areas establish interchange schedules through a multi-stage selection process that uses a merit-order list of generation resources. In addition, certain restrictions are applied to prevent the first Control Area from scheduling all the highest merit generation in his area to the load in his area. The software model does not track pricing of services, metering of services, or billing for services. A simplified model is employed for Interconnected Operating Services (IOS), also called ancillary services. The model schedules only two types of services: regulation, and contingency reserve. Regulation, as used in this model, combines regulation and load following services. Contingency reserve, as used in this model, includes spinning reserve, non-spinning reserve, and interruptible load. Contingency reserves are dispatched from generation resources first and interruptible load last. These terms are defined in the Draft NERC Policy 10 (IOS). The amount of each IOS that is required is determined by a simple scale factor applied to the forecast load for each scheduling time interval and each Control Area.

2.1.3.2 Planning phase

The planning phase operates in the following way. Schedules are established by each Control Area before the start of each day and are not changed during the day. This is a simplified way to represents a day-ahead market but does not try to represent an hour-ahead market. Each Control Area must establish schedules for the total of the forecast loads within its area from generators both within its area and in other Control Areas. Generators and loads within a Control Area are called native generators and loads for that Control Area. The schedules between Generator Entities and Load-Serving Entities that are each within a Control Area are known as schedules serving native loads or just schedules. The schedules will be established at 100% of the forecast loads. Actual loads above the forecast level will be supplied by IOS regulation services. Actual loads below the forecast level will be balanced by dispatching generator units at less than scheduled levels. The schedules between Generator Entities in one Control Area and Load-Serving Entities within another Control Area are known as interchange schedules. During the interchange scheduling process, it is assumed that there is adequate transmission capacity to get the power from the scheduled generator buses to the load buses. This assumption is tested by a DC power flow analysis at the fourth stage in the process. Interchange schedules are established at full forecast load levels. There may be some Control Areas where the required regulation services must be adjusted because a large share of its load is supplied with interchange power and the simplified model does not provide for regulation services from other Control Areas.

Each generation resource in a Control Area is assigned a relative cost of production by the grid modeler. This produces a merit-order list of generator units. Generator units are designated to operate in setpoint or AGC modes. In setpoint mode, the generator unit does not automatically follow changes in load. This is modeled to represent base-load units like nuclear power plants. In AGC mode, the Control Area senses changes in frequency and dispatches new loading signals to generators according to the system frequency response characteristics and scheduled interchange flows. Since we do not model frequency changes, a similar effect is obtained by having the Control Area calculate the generation-load imbalance and send AGC dispatch commands to all generator units in AGC mode. The capacity of generator units is divided into generation, regulation and contingency reserve. Since the model does not consider market issues, the only significance of this classification is related to the sequence of scheduling and dispatching generation resources. When establishing schedules, the highest merit-order generators that have remaining capacity are selected. A particular generator unit may have schedules to supply power to several Load-Serving Entities located in several Control Areas. Generator unit startup requirements and ramp rates are not modeled at this time. The model provides for interruptible load. Selected buses are assigned an interruptible load capability that is a percent of the forecast load for that bus. The interruptible load is treated as a generation resource with the lowest merit-order rank. Only the Control Area containing the interruptible load is allowed to dispatch the load curtailment.

The first stage of the scheduling process schedules real power for native loads. Each Generator Entity within a Control Area sends a generation plan to its Control Area. Each generation plan specifies real power capacity and regulation service capacity if a portion of the generator capacity is to be reserved for regulation service. Each Load-Serving Entity sends a load forecast to its Control Area. The load forecast is based on the load profiles associated with the grid model. The load profiles vary by week of the year, day of the week and hour of the day. The load forecast includes real power for each bus for each hour. The Control Area forms schedules between native generators and native loads until up to 70% of the generation capacity has been scheduled for each generator unit. In off-peak hours, this may satisfy the entire native load. When this stage of scheduling is complete, each Control Area sends each other Control Area the merit-order list of its generators and the available capacity remaining for each generator unit.

The second stage of the scheduling process establishes interchange schedules between Control Areas. The Control Areas are arbitrarily assigned a sequence number for this stage. Applewood is first, Beech is second, and Cherry is third. The first Control Area schedules its remaining native load by selecting the highest merit-order generators with available capacity from either its native generators or any of the generators in other Control Areas. The only limitation is that no more than 10% of the total capacity for any generator unit can be schedules at one time. The first Control Area updates the prioritized lists of all generators and sends them to the second Control Area along with a token, which releases control to the second Control Area. Each Control Area repeats this step in turn until all native loads are scheduled. More than one round of scheduling may be required. As the final action of this stage, each Control Area sends its complete list of schedules to the Security Coordinator.

The third stage of the interchange scheduling process performs a DC power flow analysis to determine if transmission lines are projected to be overloaded. The Security Coordinator assembles all the schedules, formats the data as necessary, and performs a DC power flow analysis for each hour. The results of the analysis are real power flow in each transmission line. Reactive power flows and bus voltages are not considered in the power flow analysis. The Security Coordinator sends the results to the Transmission Service Provider.

The fourth stage identifies whether the schedules, as established, may result in transmission line overloads. The Transmission Service Provider compares the power flow predictions with the operating limits for each transmission line. Any locations where the predicted power flow is more than 85% of the operating limit is identified and displayed for the appropriate Control Area operator. The model does not incorporate a procedure for resolving operating limit violations.

The fifth stage schedules IOS within each Control Area. We assume IOS resources are adequate within each Control Area to provide all the services required. A very simple procedure is used to determine the required IOS. Regulation services are set at 15% of the total native load for the Control Area. The Control Area schedules regulation services from the generator units within the Control Area. Contingency reserves are set to 10% of the total native load or the scheduled capacity of the largest generator unit in the Control Area. The Control Area schedules the contingency reserves from generator units within the Control Area excluding the largest generator if it raised the requirement above 10%. The Control Area schedules both of the two types of IOS from generator units within the Control Area. When generation resources within the Control Area are not sufficient to meet contingency reserve requirements, the Control Area will display a warning message for the Control Area operator.

2.1.3.3 Real-time operations phase

The real-time operations phase performs several functions. At one-minute intervals, generation-load balance calculations are performed and generation adjustments are dispatched to match generation for the next minute and the actual load from the current minute. This process models Automatic Generation Control (AGC) functions. Since the generation adjustments are made based on the actual load from the previous minute, there will usually be some generation-load imbalance. As a result, the tie line power flows between Control Areas will not exactly match the interchange schedules. At ten-minute intervals, a DC power flow analysis is performed to determine actual tie line flows between Control Areas. The difference between interchange schedules and actual tie line flows between two Control Areas is Inadvertent Interchange. The security Coordinator will accumulate and report to each Control Area the net Inadvertent Interchange for the previous hour. The model does not have any mechanism to settle Inadvertent

Interchange. Also at ten-minute intervals, each Control Area will redispatch generation to more effectively use high merit-order generator units. The results of the DC power flow analysis is sent to the Transmission Service Provider which checks for operating limit violations.

Generation-load balancing must account for the interchange schedules that are established during the planning phase and remain constant during the hour. The Net Scheduled Interchange (NSI) is the sum of all interchange schedules for a Control Area with all adjacent Control Areas where a positive value is power flow out of a Control Area and a negative value is power flow into a Control Area.

Each Load-Serving Entity at each one-minute time step calculates actual loads by linearly interpolating between the forecast loads for each hour, which is assumed to apply at the start of each hour. This is adjusted by a random variable from a normal distribution with a standard deviation of 5% of the forecast load and with smoothing to approximate a 10-minute time constant. The result is a value that approximates the forecast load values but changes minute by minute with some random variation.

At one-minute intervals, each Control Area calculates a generation-load imbalance from scheduled generation minus NSI minus actual loads. To simulate the automatic load tracking of generator units in AGC mode, the Control Area sends an AGC dispatch to each generator unit that is in AGC mode. The dispatch for each generator unit is proportional to the scheduled generation for that unit. The AGC dispatch can be either positive producing increased generation or negative for decreased generation.

At ten-minute intervals, each Control Area submits its generation dispatch for the last minute of the previous interval and actual loads for the initial minute of the current interval to the Security Coordinator for a DC power flow analysis. The results of the analysis are sent to the Transmission Service Provider who checks for operating limit violations and reports them to the Security Coordinator and the appropriate Control Area. Warning messages are displayed to the Security Coordinator and the Control Area operator. The Security Coordinator calculates the Inadvertent Interchange between each pair of Control Areas and accumulates the values for a report to the Control Areas at the top of each hour. In addition, the results of the analysis are sent to the Control Areas so that they can calculate a value that simulates ACE. It is calculated as net actual interchange minus NSI.

Each Control Area redispatches generation in its area at the initial minute of each ten-minute interval. The logic for the generation dispatch proceeds as follows. Determine the imbalance between the hourly generation schedules established during the planning phase minus the NSI minus the actual loads. If the imbalance is positive, reduce interruptible load curtailment, if any, then dispatch decreased generation from the lowest merit-order generator unit until it is zero and then the next lowest merit-order generator unit until the imbalance is met. If the imbalance is negative, then dispatch additional generation from the highest merit-order generator units that have been scheduled to provide regulation services followed by generator units that have been scheduled to provide contingency reserve services. As a last resort, dispatch contingency reserves services from interruptible loads. Whenever contingency reserve generator units are dispatched, then display a warning to the Control Area operator. Whenever contingency reserve interruptible loads are scheduled, then display a warning to the Control Area operator and send a message to the Load-Serving Entity directing the location and amount of interruptible loads to be curtailed.

2.1.4 Subset of the Problem to be solved

2.1.4.1 Pieces of the System

Figure 6 contains a legend for reading class diagrams.

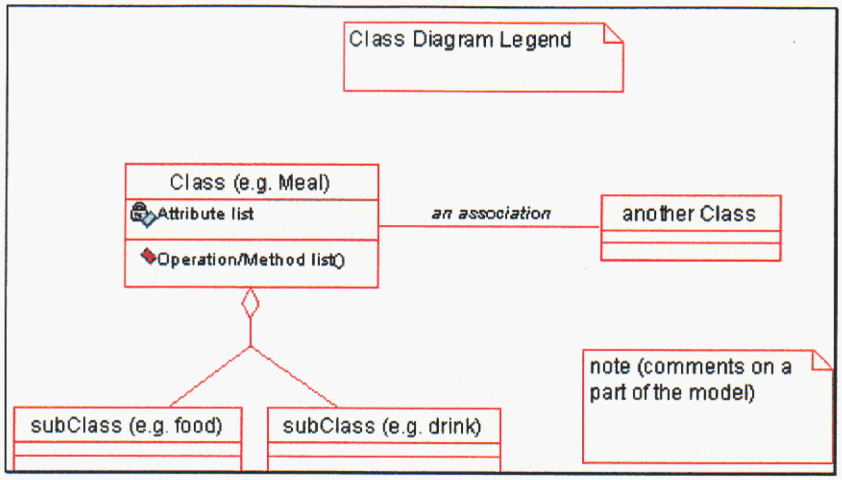


Figure 6 - Class Diagram Legend

Figure 7 shows the components that our simulation power grid will cover.

This project develops a simulation power grid model based on the IEEE Reliability Test System- 1996 [IEEE-RTS-96]. The simulation power grid is organized into three nearly identical Control Areas with five inter-area tie-lines connecting the areas. The simulation power grid has a total of 76 buses, 96 generator units, and a total of 120 transmission branches that include lines, cables, transformers, phase-shifter, and tie-lines. The bus and line numbering plan are preserved from RTS-96. The optional DC link is not used.

Several extensions to RTS-96 are made. It is assumed that all three Control Areas are under a single Security Coordinator. All generator units are assigned to four generator entities. The grid model is divided into one Transmission Service Provider for the entire model and four Load-Serving Entities for each Control Area. A portion of the load from selected buses is assumed to be interruptible load. A merit-order for dispatching generator units is defined. Generator units are removed from service for annual maintenance for the weeks listed in the paper on extensions to the RTS [IEEE-RTS-86].

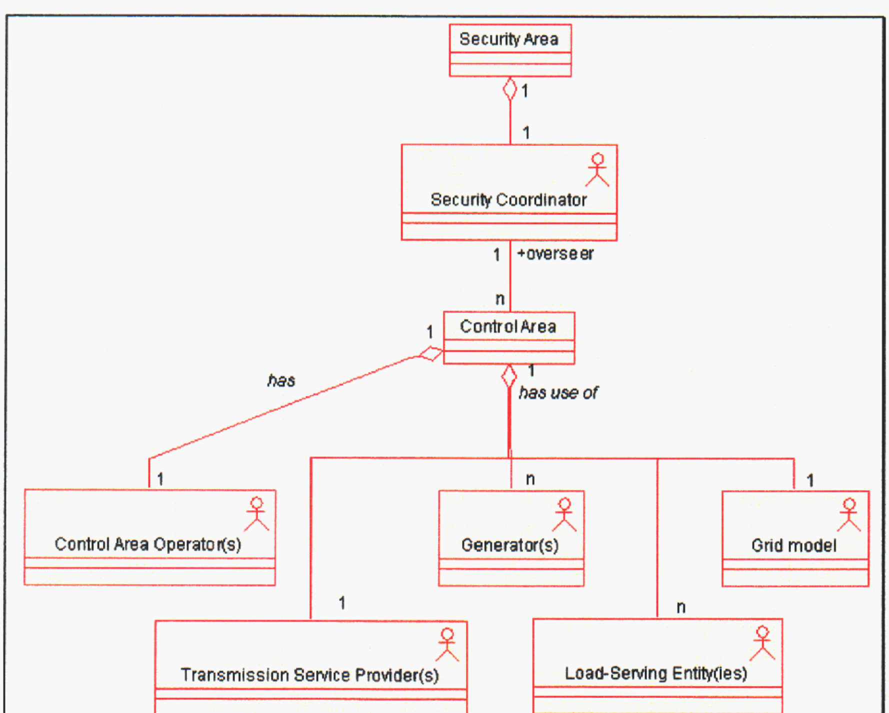


Figure 7 - Class Diagram of Our Power Grid

2.1.4.2 Simplifications to the System

The simulation power grid software model does not incorporate the market mechanisms that set prices or determine bilateral transactions among the for-profit market entities. Neither is the electronic tagging process modeled in detail. Instead, Control Areas establish interchange schedules through a multi-stage selection process that uses a merit-order priority list of generation resources. In addition, certain restrictions are applied to prevent the first Control Area from scheduling all the highest merit generation in his region to the load in his region. The simulation power grid software model does not track pricing of services, metering of services, or billing for services. For this version of the SRS, only real power is modeled. Transmission line losses are assumed to be zero and all bus voltages are assumed to be 1.00 per unit. A simplified model is employed for Interconnected Operating Services (IOS), also called ancillary services. The model considers only two types of services: regulation and contingency reserve. Regulation, as used in this model, combines regulation and load following services. These terms are defined in the Draft NERC Policy 10 (IOS). The amount of each IOS that is required is determined by a simple scale factor applied to the forecast load for each scheduling time interval and each Control Area.

2.1.4.3 Data Flow in the System

Figure 8 contains a legend for Data Flow Diagrams.

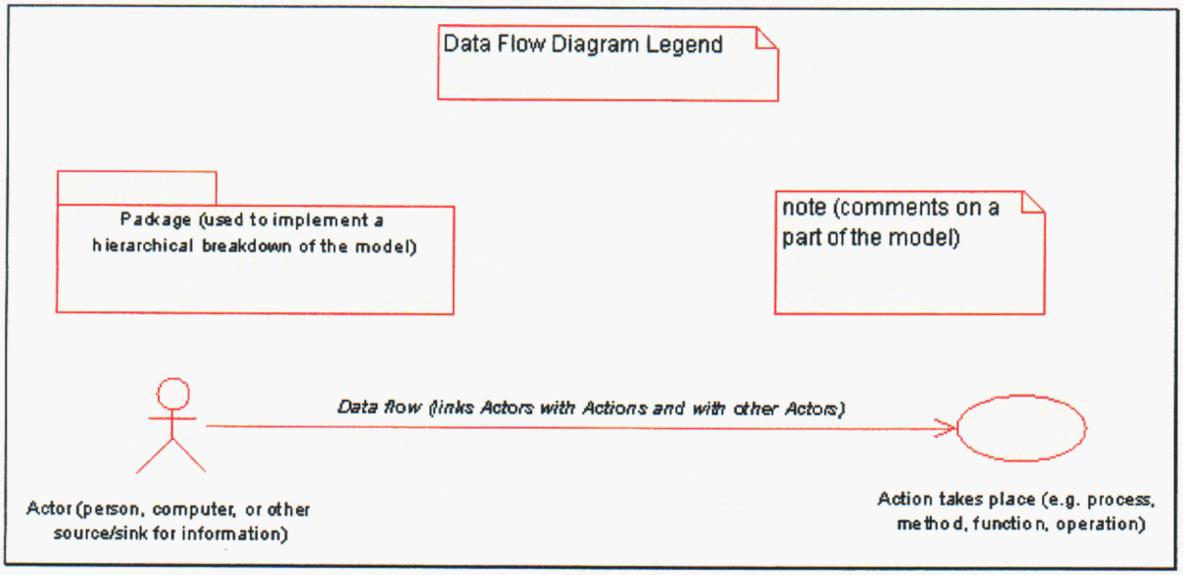


Figure 8 - Data Flow Diagram Legend

Figure 9 is a Data Flow Diagram Level 0, or Context Diagram, of the system. It shows the "actors" or "sources and sinks" for the data. These same actors were shown above in Figure 7. The Data Flow Diagram shows how data flows through the system. It identifies which actors produce and consume each data item. In chapter 3, you will see further functional decompositions of the data flow diagram. The "bubble" in the center is the process that acts on the data.

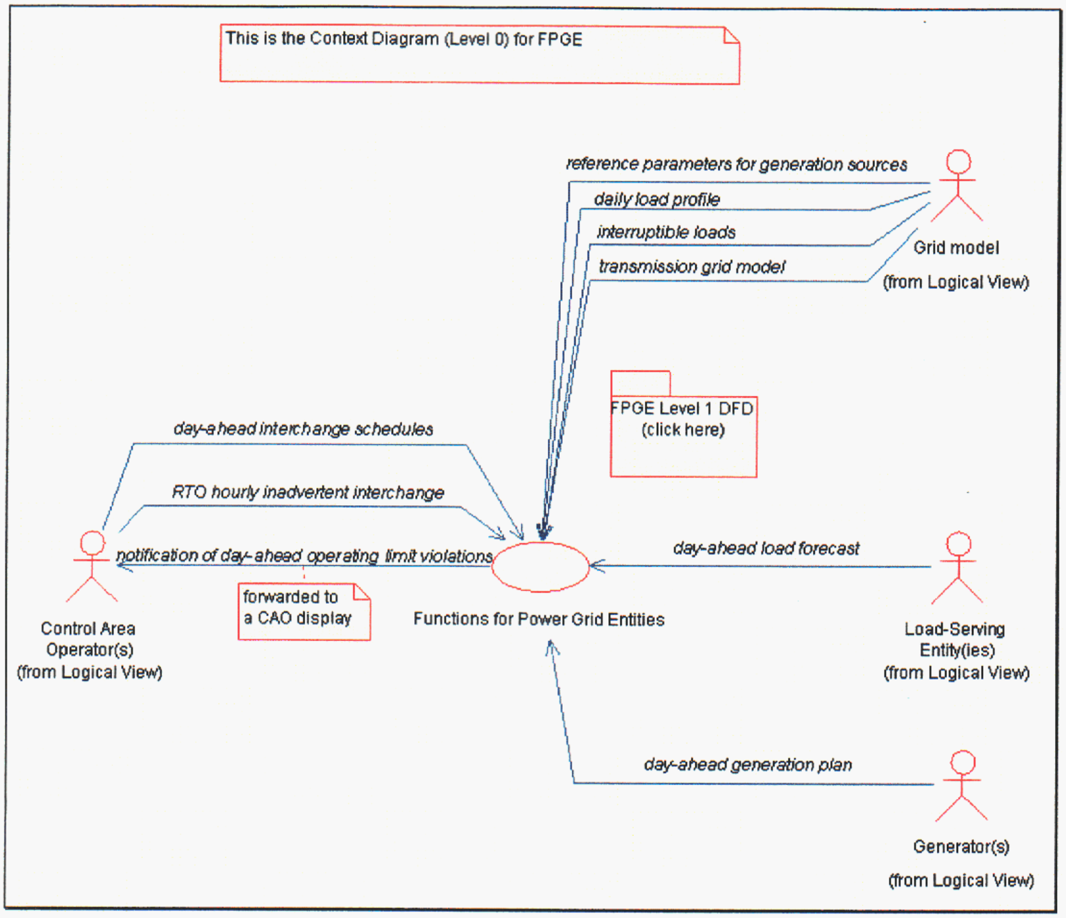


Figure 9 - Data Flow Diagram - Level 0

2.1.4.4 Prototype Agent System

We have developed a Prototype Agent System (PAS), a prototype hardware test bed upon which multiple networked agents perform the functions associated with information communications among Load Serving Entities, Control Area Operators, and a Security Coordinator. Specifically, we built a representative network of ten Linux-based servers networked with standard TCP/IP protocols (Internet protocols). A software agent developed with Sandia's Secure Agent Architecture II inhabits each server. Nine agents (eight Control Area Agents and one Security Coordinator Agent) function as a closed, secure multi-agent system conducting collaborative operations associated with real-time operations. Load-Serving Entities are represented by time processes that periodically send messages to the Control Area Operator agents. The agents have cyber-security capabilities and employ secure multiparty cryptography to ensure robust operations immune to external cyber attacks and certain attacks from malicious insiders. A tenth agent will inhabit the tenth server to facilitate network monitoring and perform standard and special cyber attacks and introduce various types of operator errors in the multi-agent system with the objective of disrupting simulated real-time operations (e.g., interrupting communications and penetrating security). This prototype follows the prototype agent test bed outlined in [IA-IDCEPG] and shown in Figure 10.

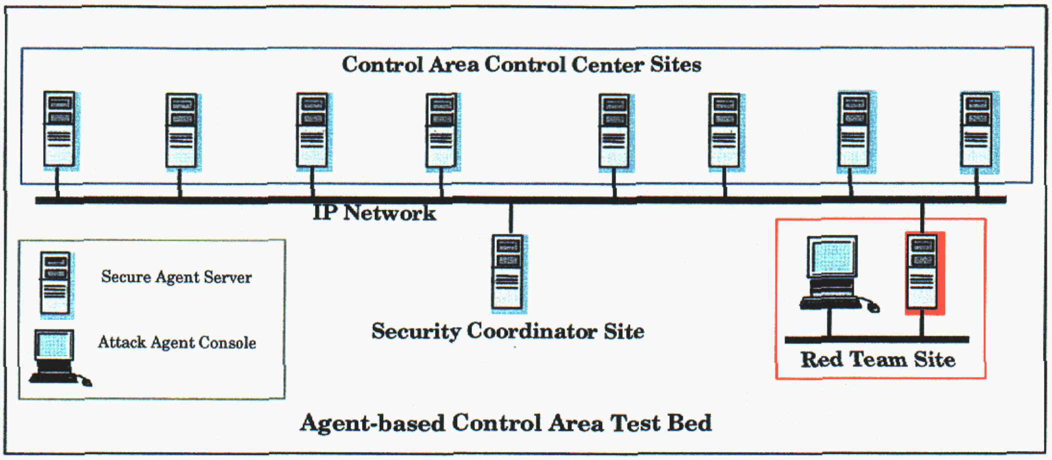


Figure 10 - Control Area / Security Coordinator Test Bed

There are discrepancies between the PAS presented in this section and the system or systems discussed elsewhere in this report. These exist because the PAS communication schemata (see Figure 12 through Figure 15) were delineated several months ago based on the then-current data flow diagrams. By *schema* (pl. schemata) we mean a network of state descriptions, attached pre- and post-conditions, and relevant actions, arranged to signify that the actions, if executed by a given agent under the associated pre-conditions, will result in the change in state indicated by the schema, including the explicitly indicated post-conditions. Subsequent work by team members not directly associated with the agent system resulted in modifications to the data flow that were not incorporated into the PAS. As a result, the PAS and the current understanding of data flow are not the same. Based on the accuracy with which we captured the working data flows at the point of departure for prototype development, we believe there are no obstacles to realization of an agent system that accurately captures current data flows. Figure 11 shows a Control Area Operator's notification screen.

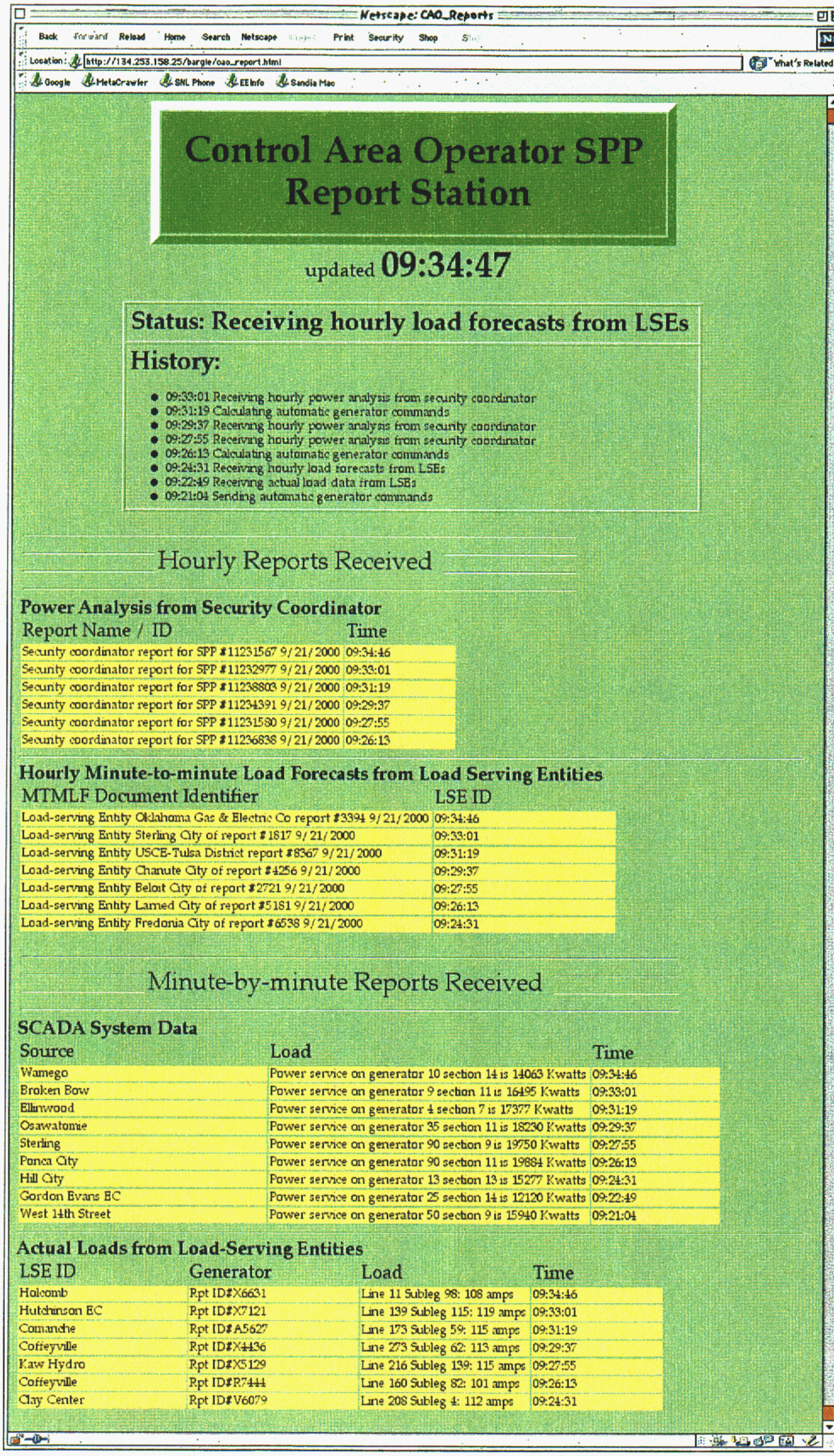


Figure 11. Control Area Operator's notification screen

Assumptions and scope comments for the Prototype Agent System:

1. The PAS is directed at the operations phase of power grid operation and executes no specific functionality to support the planning phase.
2. The intent of the PAS is to establish communication patterns required for operation of the electric power grid by agents. The PAS therefore does not simulate or model the operation of the power grid but executes genuine communication acts as required by power grid operations. Descriptions below are intended to narrate the process by which information gets created and transmitted; in particular, referenced forecasting and simulation steps are not actually executed by PAS agents, although a significant body of code already exists to enable that.
3. Issues of command, control, and communication security are basic to the Secure Agent Architecture. The otherwise simple communication activities accomplished in the PAS are fully protected by encryption and digital signature. Secure operation is fundamental to our agents and we believe it to be a fundamental requirement of any system operating the national electric power grid.

Description of how the PAS operates:

At the top of every hour:

1. Each Load-Serving Entity (LSE) forecasts its minute-by-minute load for the coming hour and sends this data to the appropriate Control Area Operator (CAO).

Assumption: The "appropriate" CAO is the CAO of the Control Area within which the LSE resides.

2. Each CAO combines the load forecast from its LSEs with day-ahead planning data from the day before and its own Automatic Generation Control (AGC) commands from the previous minute to adjust its native load schedule for the coming hour.

Assumption: "native" means for loads within the Control Area governed by the CAO.

3. The adjusted native load schedule goes to the Security Coordinator (SC), who uses the information from all CAOs to compute an overall power flow analysis (PA).

Assumption: This analysis is valid for the hour within which the calculation is performed.

Assumption: The PA consists of a maximum power flow value valid for the coming hour for each transmission line.

Assumption: All CAOs get the same full PA and each extracts the subset relevant to itself.

4. The PA is forwarded to the Transmission Service Providers (TSPs) as well. We understand that the full PA is provided and could go directly to the TSPs from the SC because the CAO adds no information to the PA. Upon receiving the PA, each TSP reports any operating limit violations on its transmission lines to the appropriate CAO(s). The intent is that the CAO would adjust power flow based on notice of a violation, but currently the system plays no role in this adjustment except to display the violation.

At the top of every minute:

5. The LSE uses the PA, the hourly load forecast, and SCADA information to calculate actual loads at the top of each minute of the hour for which the PA is valid. These minute-by-minute loads are actual real-time usage and are sent to the CAO.
6. The CAO uses actual minute-by-minute load information from its LSEs to calculate how much regulation to dispatch and how this amount differs from the load forecast. The difference is called the Area Control Error (ACE).
7. The CAO uses the dispatched power amounts and the ACE to determine a set of Automatic Generation Control (AGC) commands. These are issued directly to the generating facilities, without reference to the LSEs.
8. The generators deploy power according to the commands and consequently cause signals to flow on the Supervisory Control and Data Acquisition (SCADA) system. The SCADA system is accessed by the CAO.
9. When dispatched power is determined in step 5 above, the CAO has sufficient data to decide that some generators will be over-capacity. This is transmitted to the LSEs when and if it occurs.

State descriptions for Electric Power Grid Agents and ancillary entities

Security coordinator (SC). Refer to Figure 12.

State 1: Quiescent; reception of hourly power flow analysis confirmed by all intended recipients; waiting for some CAO to send an Adjusted Native Load Schedule (ANLS)

State 2: At least 1 but not all ANLSs received from CAOs

State 3: All ANLSs received; calculating power flow analysis (PA)

State 4: PA complete; transmitting to CAOs, Load-serving entities (LSEs), and Transmission Service Providers (TPSs).

State 5: PA sent to all intended recipients; waiting for confirmation from CAOs.

Control Area Operator (CAO). Refer to Figure 13 and Figure 14.

State 1: Quiescent

State 2: Have received actual load data from at least 1 but not all LSEs; HAVE NOT received power flow data from SCADA system

State 3: Have received actual load data from at least 1 but not all LSEs; HAVE received power flow data from SCADA system

State 4: Have received actual load data from all LSEs but HAVE NOT received power flow data from SCADA system

State 5: Have received actual load data from all LSEs and HAVE received power flow data from SCADA system; no insufficient resources, calculating AGC commands

State 6: Have received actual load data from all LSEs and HAVE received power flow data from SCADA system; insufficient resources; transmit insufficient resource warning to appropriate LSE; calculating AGC commands

State 7: AGC commands complete; transmitting to generators

State 8: AGC commands complete and transmitted

State 9: Have received hourly minute-to-minute load forecast from at least 1 but not all LSEs

State 10: Have received hourly minute-to-minute load forecasts from all LSEs; calculating adjusted native load schedules (ANLS)

State 11: ANLSs complete; transmitting to security coordinator (SC)

State 12: ANLSs transmission to SC completed, waiting for confirmation

State 13: Received confirmation of reception of ANLSs by SC

State 14: Received power flow analysis from SC; sending confirmation to SC

Load-serving entity (LSE). Refer to Figure 15.

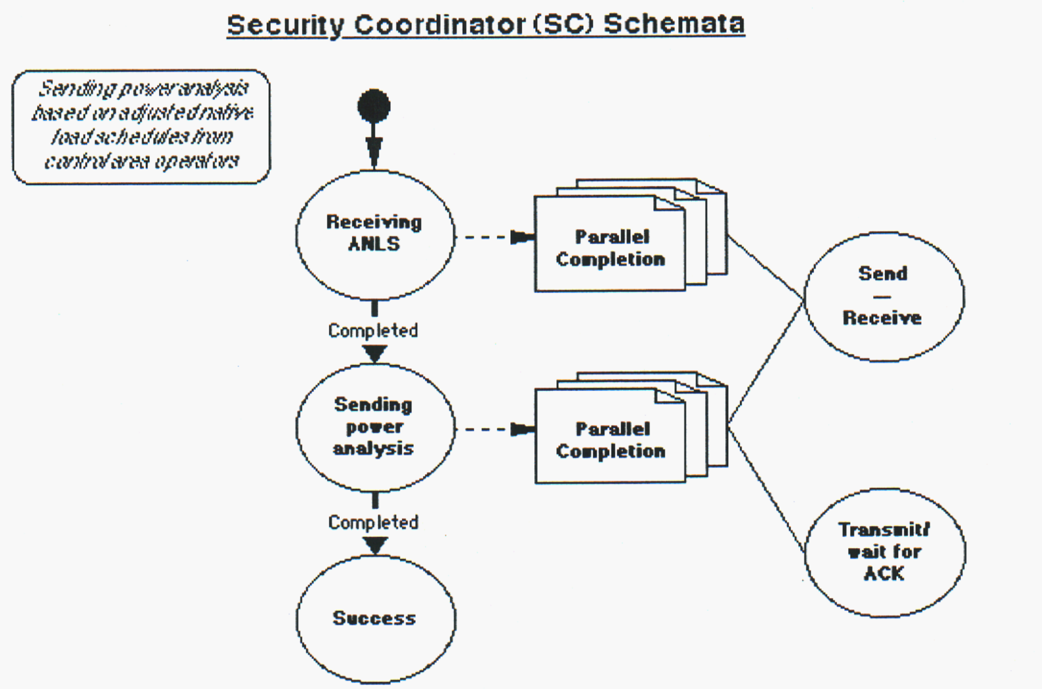
State 1: Quiescent

State 2: Hour timer fires; transmit minute-to-minute load forecast to CAO

State 3: Minute timer fires; transmit "actual load" to CAO

Generator/SCADA system (not represented explicitly by agents). Shown in lower left of Figure 13.

State 1: Randomly transmit data that indicate resources to CAO via SCADA system



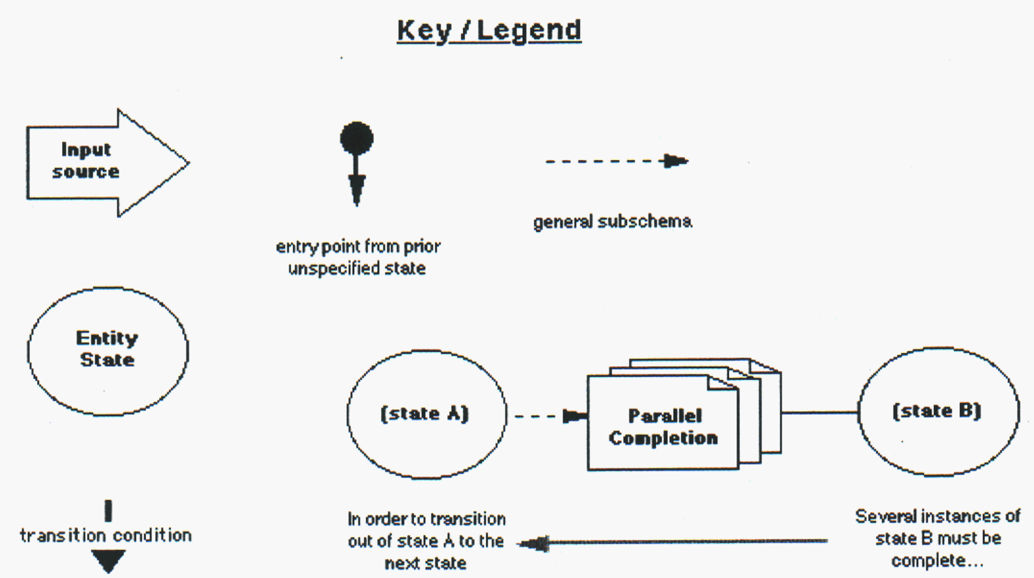


Figure 12. Security Coordinator Schemata

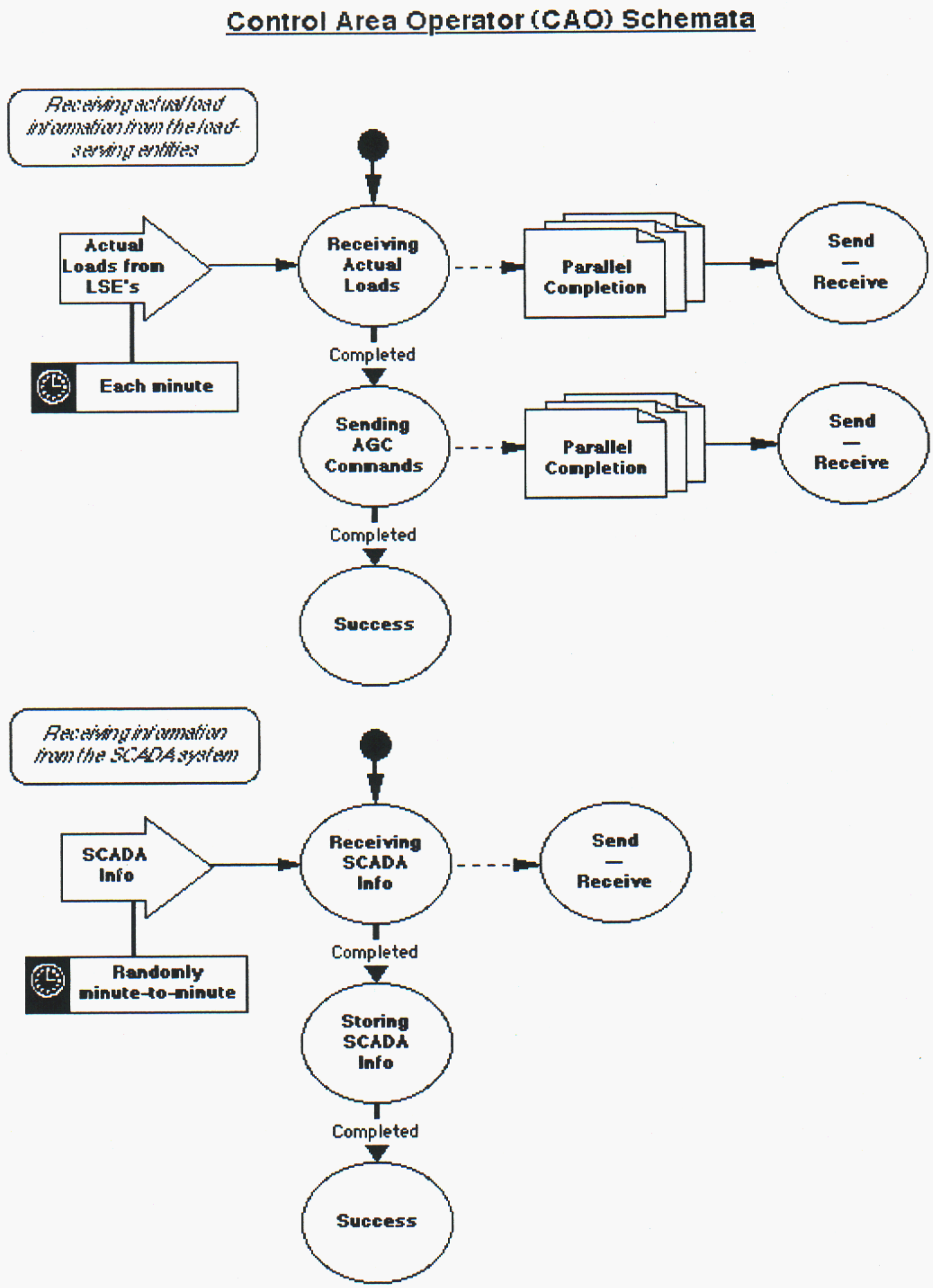


Figure 13. Control Area Operator Schemata

Control Area Operator (CAO) Schemata

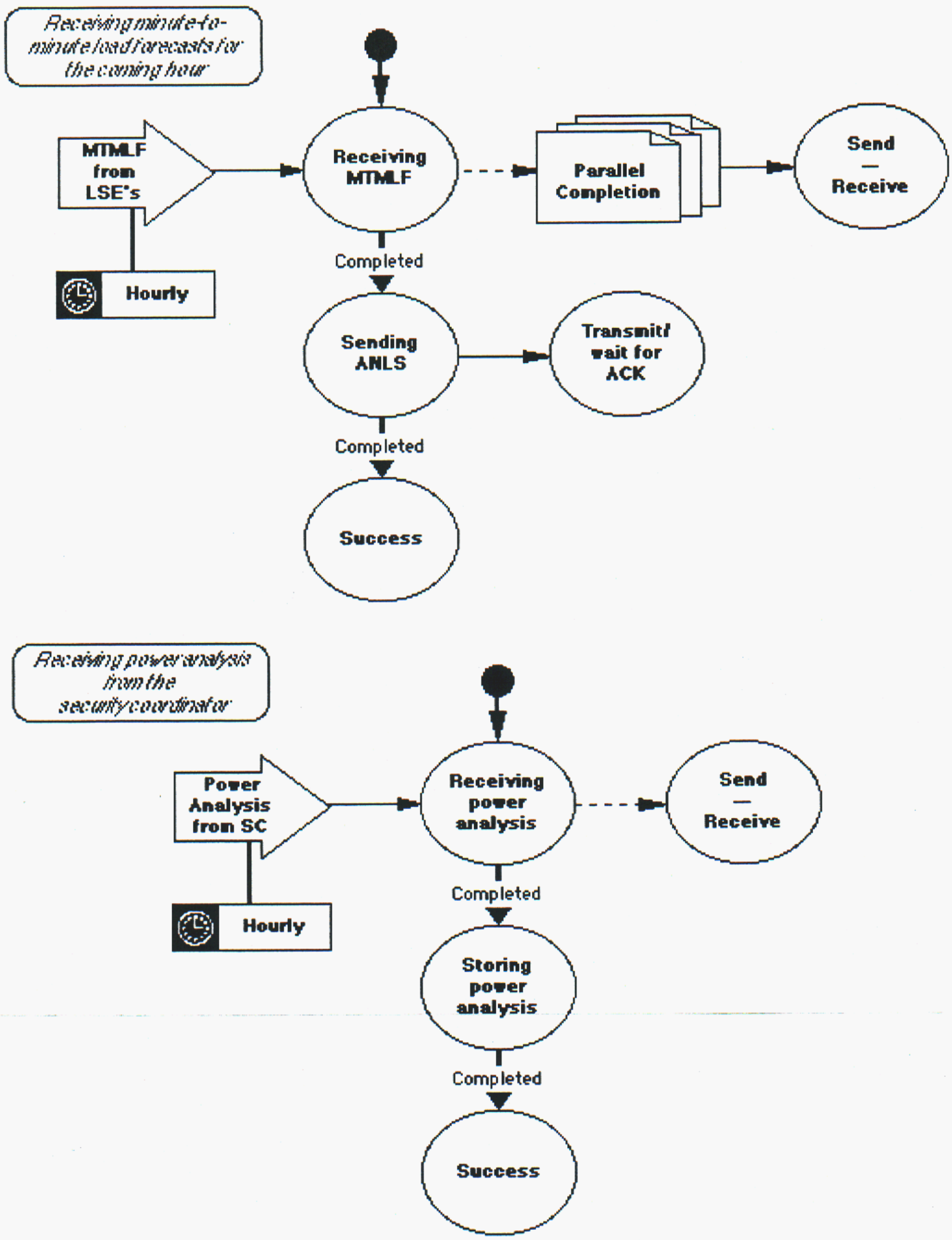


Figure 14. Control Area Operator Schemata (continued)

Load-Serving Entity (LSE) Schemata

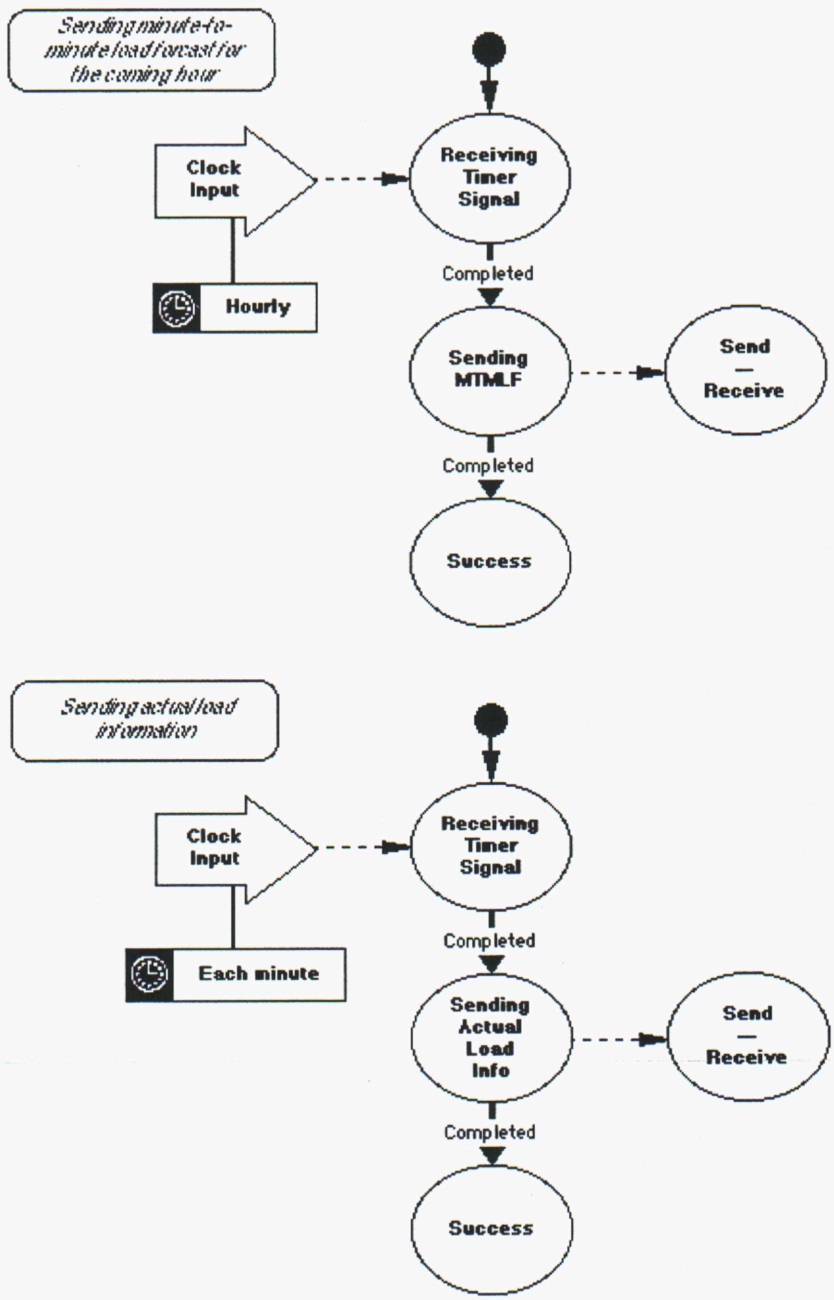


Figure 15. Load-Serving Entity Schemata

2.1.4.5 How to detect a malfunctioning agent

The discussion in Sections 2.1.4.5 through 2.1.4.8 addresses issues of agent performance and options for dealing with malfunctioning agents. The team at Washington State University prepared this discussion.

To a very large degree the question of malfunctioning agents depends upon the underlying assumptions made about the failure model of the agents and the overall application. Failure models range from ensuring nothing to ensuring that a safe and orderly shutdown of a system occurs along with the notification of another process that a given process/agent has failed. Obviously if the later is chosen, then little work will need to be done externally, but unfortunately ensuring a completely fail-safe model is extremely difficult.

More concretely, a failure model extends the legal behavior of a component (i.e., its specification) into ways in which it can legally fail. This is to allow the expected classes of failures to be explicitly enumerated and handled, and unexpected failures not handled. Examples of failure models, from strongest (in terms of assumptions about the failure) to weakest (more realistic, but harder to program) are:

- Fail-Stop: fails cleanly (no bad outputs) and detectably (its failure status can be queried)
- Fail-Silent (aka "crash): fails cleanly but undetectably: you must infer that it has failed by an external mechanism/protocol, for example it has not send a required "I'm alive" message for too long.
- Timing: an answer/command arrives too late or too early
- Value: the wrong answer/reply is delivered
- Byzantine (aka "arbitrary"): no restrictions on the way it can fail. A failed component can return different answers to the same query/round to different users, can lie about its identity, can conspire with other failed components (or other failed replicas), to try to cause the greatest harm.

Besides assuming how the system will fail, it is important for system designers to justify the appropriateness of the failure model; i.e., show reasonable cause to believe that a failure model with weaker assumptions (i.e., more can go wrong) is not likely to be mandated.

Putting aside the discussion of the failure models, the failure of an agent can be split into several different cases (as viewed from the outside). Cases 1 and 2 require no modification to the agents, whereas the other cases require at least some modification to the agents or agent systems.

2.1.4.5.1 Case 1: Can observe external behavior

No changes to the agent code will be required in this case. Instead, an external entity will need to be created that can observe (i.e., read/gather) the external behavior of the system. Some examples of values that may be observed are the generator's output and reserve capacity, and the frequency of the power transmission lines. These values should already be available within the system, so it will only be a matter of providing this data to the external observer. The observer will then use a set of rules to determine if the system is behaving properly. If not, then the assumption must be that one of the agents/entities within the system is malfunctioning. For example if the predicted load is increasing, but a generators output goes down (while all of the other generators loads remain constant), then one might assume that the agent in charge of the given generator has malfunctioned.

Open Issues:

- Can a sufficiently complex model of the system be created so that 'bad' behavior can be identified?
- Can 'bad' behavior be successfully traced back to the proper malfunctioning agent?

Can we distinguish between failure of an agent with failures of underlying subsystems. E.g., if some of the generators an agent controls have failed, and we notice that the agent's area is not generating what it should, we cannot just assume the agent is faulty.

2.1.4.5.2 Case 2: Can observe agent's communications (e.g., commands to the generators)

This second case, like the first, does not require changes to the agent code. If more strenuous failure guarantees were required it is a natural progression to allow for the monitoring of internal communication within the system as well as observing its external behavior. By monitoring system's internal communication, the external entity will have an easier time of pin-pointing a malfunctioning entity. For example if a generator's output unexpectedly drops from an external viewpoint it might not be possible to tell if the generator or an agent is malfunctioning. With access to the internal communication, one can observe whether an agent sent an erroneous command (and therefore is the culprit). In the absence of any messages telling the generator to lower its output, one might then be able to assume that the generator itself is failing (or can no longer generate the power needed).

Open Issues:

- Can a sufficiently complex model of the system be created so that 'bad' behavior and 'bad' messages can be identified?
- Will monitoring all communications within the system be overly burdensome on the communications layer and/or the external entity?

2.1.4.5.3 Case 3: Hear beat signal present

Modifying the agents so that they emit a heart beat signal should be a fairly straightforward modification. Given this heart beat signal, the external entity could simply note the arrival of heartbeats from each of the agents in the system. If any agent stops transmitting heartbeat messages, then one could assume that it had failed. (In general, in an arbitrary distributed systems with unbounded communication delays, it is impossible to distinguish between a failed component and one which has been partitioned due to communication failures.) Of course this is a fairly primitive failure detection mechanism because rather than detecting malfunctioning agents it only detects dead, hung, or disconnected agents. In other words, it is only appropriate when the assumed failure model is fail-stop or fail-silent.

Open Issues:

- Will the heartbeat signals overwhelm the network?
- How much damage could a malfunctioning agent do before it either dies or shuts down? I.e., can we really assume it is fail-silent? Why is this assumption justified?

2.1.4.5.4 Case 4: Have replicated agents and voting

A much more fault tolerant approach to solving the malfunctioning agent would be to replicate the agents of concern [Schneider, 1997]. When a choice or command is issued by the replicated set of agents, each agent would cast a vote for what it wanted to do next. A malfunctioning agent could possibly cast votes in opposition to the rest of the replicated agents. Thus in a matter of time, it would be recognized as malfunctioning.

Several replication and/or voting schemes could be used to replicate the agents and vote upon their actions. For example, active replication is one such approach and its use would result in each replica receiving and processing all commands/inputs on their own. Active replication works only when the actions of the agent are deterministic. Voting schemes could include simple majority logic, threshold logic, or computing the average, median or mode of the results.

Open Issues:

- Can the logic of the agent be modeled without any inherit errors? (Otherwise all n copies of the agent will all do the same wrong thing.)
- Will the replication and voting costs be too high for the system at hand?
- Will Byzantine failures be likely occur?

2.1.4.5.5 Case 5: N-version agents

If the cost of failure is high enough, N-Version programming might become an viable option. N-Version programming is based upon developing N different working implementations of the application, not just creating n identical replicas. The development costs will be quite high since N separate development teams each need to develop a working solution to the problem. Preferably, some of these implementations will be implemented on different hardware platforms as well (in order to account for any unforeseen hardware errors).

Once the n versions are developed, the deployment is quite similar to having n replicas. Each of the n versions will produce results. These results will be combined in a voting engine and an official result will be picked. If one agent begins to malfunction the voter will be able to recognize its divergent results and thus mark it 'bad.'

Open Issues:

- Can an error free specification be created so that each implementation will be correct? (Otherwise a specification error will be propagated to all of the implementations).

Will the additional development costs be justified?

2.1.4.6 How to spawn a new agent

Spawning new tasks within a system or on a remote system is in and of itself a difficult task. Commands such as 'rsh' (remote shell) were developed at a fairly early stage so that a user could remotely attach to another machine and start a process on it. These commands are effective, but they also raise security issues and other issues of trust, because remote users are being allowed access to a given machine.

Recently, pattern based computing developments have produced the concept of a factory pattern. The pattern basically presents the idea that at times it is very useful to have a software factory that can produce widgets of a given type. As applied to this problem, an agent factory would be produced that would know how to produce and deploy new agents.

In both cases a certain level of management infrastructure must be put into place. For example, a factory object must be placed on each host that might possibly need to create an agent, and it must be able to access the agent's executable (or Java .class) file to start it. Also, security issues need to be part of this infrastructure; e.g., which principals have what rights to create what agents on which hosts, etc.

Being able to spawn a new agent is of limited use, unless the agent is spawned at the correct time. Having either too many or too few agents at one time can be equally poor. The management infrastructure could be human based (i.e., an operator at a control terminal) or a software based management agent (or daemon process) could be in charge of agent creation. In either case a set of rules must be developed and codified so that the management entity will know when, where and how to create/spawn a new agent.

Open Issues:

- What kind of management infrastructure will be set up to control the spawning of new agents?

2.1.4.7 How to allocate an agent's tasks to other agents

Reallocating tasks amongst the agents is a major design decision. Another related design decision is be how many tasks could a single agent perform. If an agent is only allowed to perform one task at a time, then the problem of task reallocation is really a question of agent creation/destruction, with the task being passed in at creation. If tasks can be reallocated between agents, then either a centralized or a decentralized process must be put in place in order to handle the task reallocations.

A centralized task reallocation process would require the addition of another process/entity that would store all of the current task assignments. Each agent would be responsible for communicating with this centralized process in order to accept/decline task assignments. If a decentralized process is used, then a central, single point of failure is eliminated, but in its place a inter-agent coordination mechanism must be put in place so that agents can decided amongst themselves which agent will accept a task allocation.

It is not clear as to why an agent would need to transfer its task to another agent. The most likely cause would be when its failure is imminent. If agents were replicated, no task transfer would be required. What would happen is that a replica would immediately take the place of a failing agent and the overall system would continue as normal.

Open Issues:

- What is the relationship between tasks and agents in a system. We note that the answers for this question really hinge on defining this relationship. If it is very simple, for example an agent controls the generation of one generator, then reallocating the agent's tasks is simply a matter of creating a replacement agent for a failed one (in the right place and with the right access rights). If a given agent can be performing many tasks, and kind or even number of tasks can be different with different agents, then this problem is much more difficult.

2.1.4.8 Contingency plans for when an agent stops performing its functions

This question depends upon

1) The underlying failure model of the agents, as well as
2) The design choices covered in the first three questions.

If more rigor can be placed into the individual agent design and development so that one can ensure that all agents fail safely, then the contingency plans can be dramatically reduced. But if an agent's implementation allows it to simply crash, leaving the system in a potentially unknown state, then a much more complicated contingency plan must be put into place. This is mainly, because the contingency plan will have to first put the system into a safe state before it can begin to respond the loss of an agent.

If agents are replicated then the contingency plan can be as simple as allowing a replica to takeover the original agent's functions (primary/backup replication) or masking the failure (active replication with voting). The second and final step is to inform the agent factory that a new replica needs to be created in order to replace the failed agent.

Part of the system's contingency plan should incorporate external controls so that a human operator can manually take over control of the system in order to put it into a safe condition. The operator might also need to be assisted by some special purpose tools/agents that would allow the operator to more quickly put the system into a known, safe operating state.

2.2 General Constraints

2.2.1 Technology Constraints

No technology constraints exist at this point in the project.

2.2.2 Safety Constraints

No safety constraints exist at this point in the project because the software produced will be a simulation or mock up of a power grid model developed for use in bulk power system reliability evaluation studies. The software will not be directly applied to a functioning part of the power grid. As this project progresses towards application in an operating power grid, safety constraints (e.g. the Control Area Operator needs to know which lines are energized and which are not for safety of human utility workers maintaining the lines, utility property, and customer property) will be considered.

2.2.3 Security Constraints

No hard physical or information security constraints exist at this point in the project because the software produced will be a simulation or mock up of a power grid model developed for use in bulk power system reliability evaluation studies, but will not be directly applied to a functioning part of a power grid. As this project progresses towards application in an operating power grid, reliability constraints (e.g. security breaches by hackers and physical security of utility equipment) will be considered.

Section 3 specifies all security requirements for this phase of development.

2.2.4 Reliability Constraints

There are no hard reliability constraints at this point in the project because the software produced will be a simulation or mock up of a power grid model developed for use in bulk power system reliability evaluation studies, but will not be directly applied to a functioning part of a power grid. As this project progresses towards application in an operating power grid, reliability constraints (e.g. reliability of service to customers, reliability to special customers like nuclear power plants) will be considered.

Section 3 specifies all reliability requirements for this phase of development.

Reliability metrics could be gathered during simulation or mock up runs that will establish strengths and weaknesses of our approach that will be addressed in future versions of this project.

2.3 Assumptions and Dependencies

N/A at this time.

2.4 Risks

N/A at this time.

3. Requirements

This chapter covers the detailed requirements on the software.

The requirement groupings follow:

Power Grid Requirements

- High Level Requirements
- Attribute Requirements
- Method Requirements
    - Planning Phase Method Requirements
    - Real-Time Operation (RTO) Phase Method Requirements

3.1 Power Grid Requirements

3.1.1 High Level Requirements

3.1.1.1 Overall Context

Figure 16 shows the class diagram for the Power Grid. The "get" and "set" methods are left to the design phase.

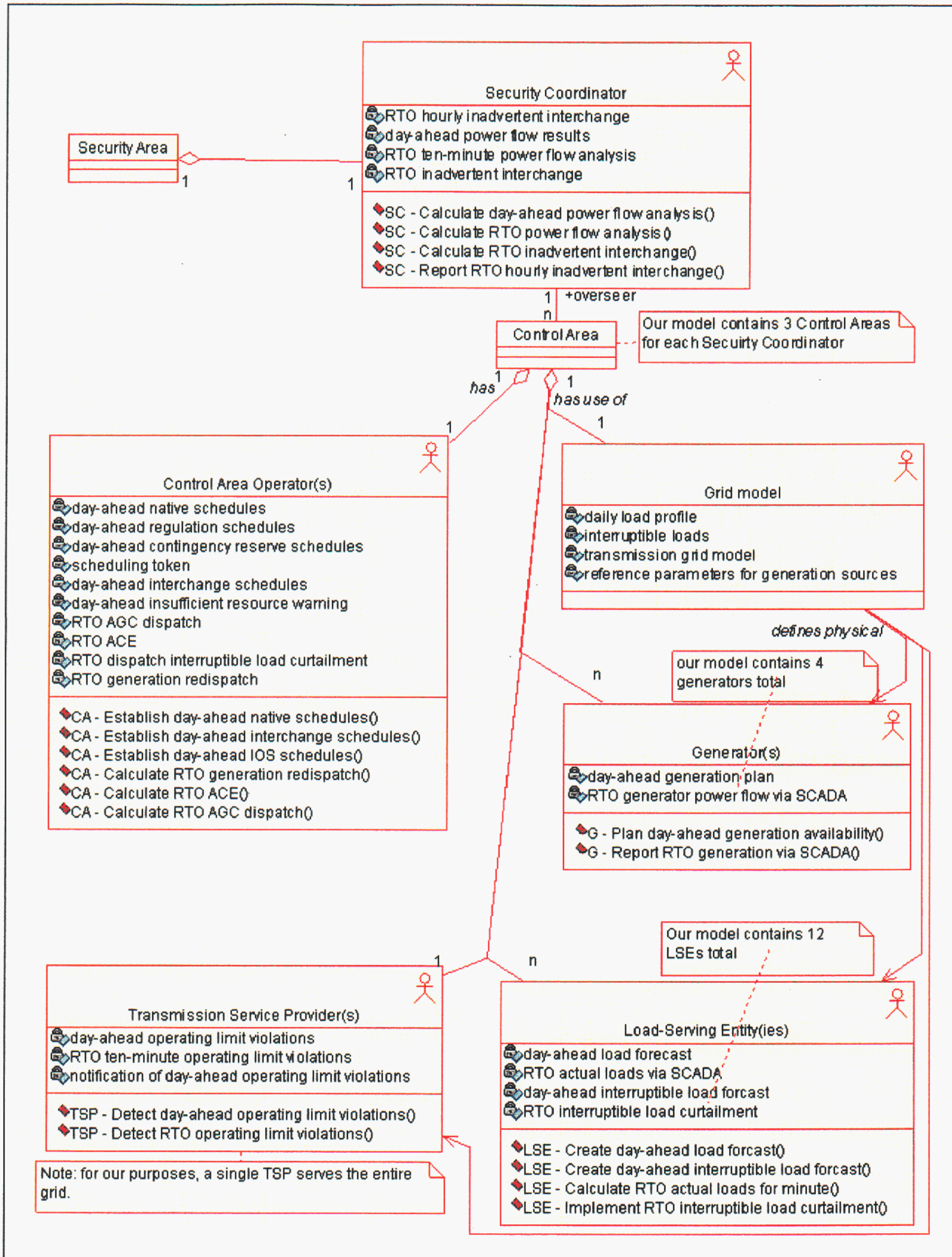


Figure 16 - Class Diagram

Figure 17 shows the simulation power grid from [IEEE-RTS96] that will be the focus of the modeling for this phase.

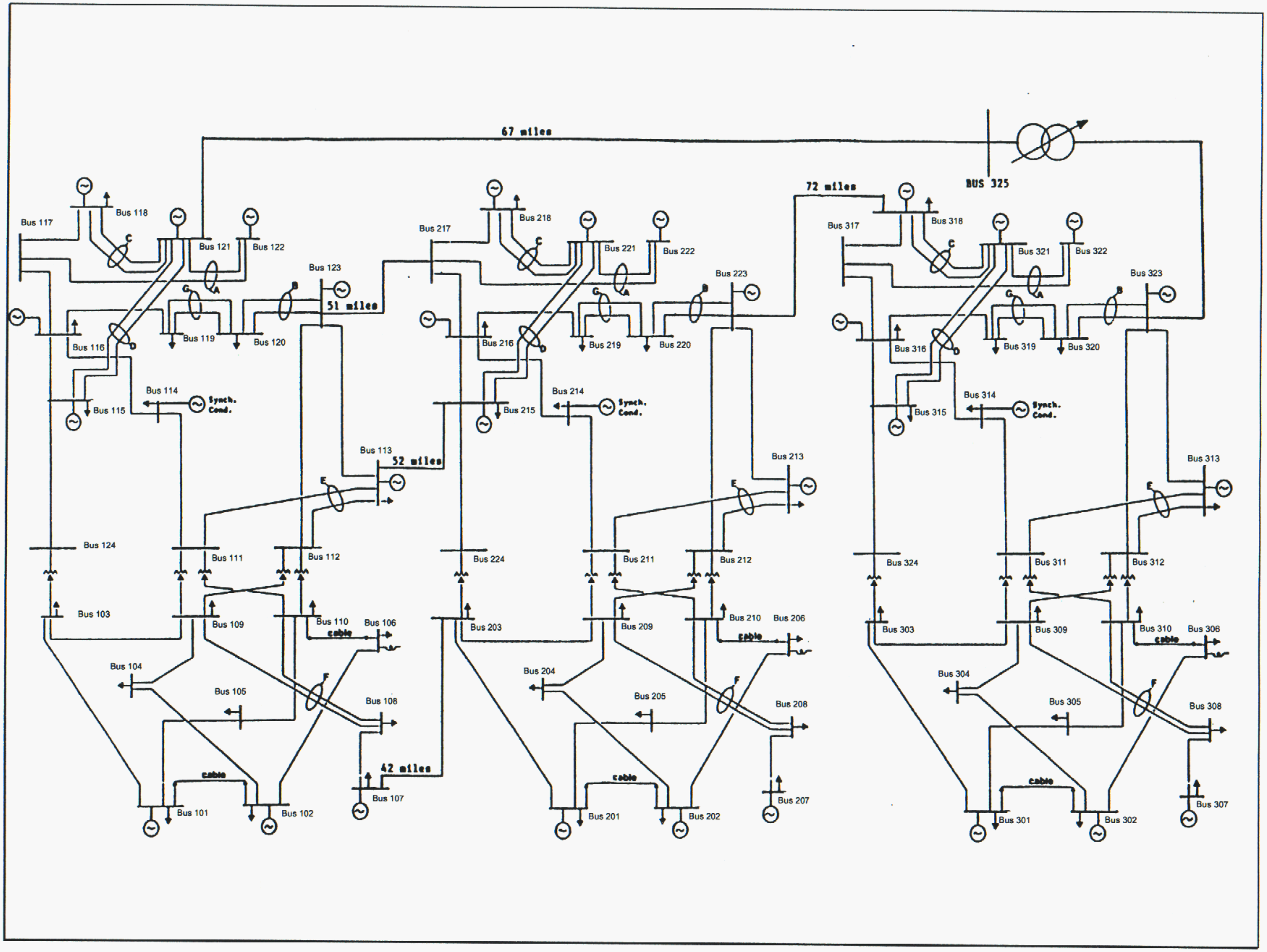


Figure 17 - The Simulation Power Grid [IEEE-RTS96]

3.1.1.2 The simulation power grid shall cover the following classes.

Requirement #: IMGC.0001.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/08/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: This bounds the classes and number of instances.

Bounds/Range: One *Security Coordinator* oversees 3 *Control Areas*. Each Control Area has five component parts: one *Control Area Operator* at any one time, one *Transmission Service Provider*, four *Generators*, twelve *Load-Serving Entities*, and one *Grid model*.

Active during: Always

Source(s): N/A

Format: N/A

Methods: N/A

3.1.1.3 The simulation power grid shall have the following Generators and configuration of generator units in the indicated Control Areas.

Requirement #: IMGC.0058.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 07/06/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/08/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: This defines the generators and how they fit into the simulation power grid.

Bounds/Range: N/A

Active during: Always

Source(s): Extension to [IEEE RTS96]

Format: see Table 1

Table 1 - Generators

Generator Name	Applewood CA, Gen. ID	Beech CA, Gen. ID	Cherry CA, Gen. ID	Total # of units	Generation Type
Pacific Nuclear	118-1 121-1	218-1 221-1	318-1 321-1	6	Nuclear (400 MW)
Colorado Hydro	122-1, 122-2 122-3, 122-4 122-5, 122-6	222-1, 222-2 222-3, 222-4 222-5, 222-6	322-1, 322-2 322-3, 322-4 322-5, 322-6	18	Hydro (50 MW)
Black Mesa Power	115-1 115-2, 115-3 115-4, 115-5 115-6, 116-1 123-1, 123-2 123-3	215-1 215-2, 215-3 215-4, 215-5 215-6, 216-1 223-1, 223-2 223-3	315-1 315-2, 315-3 315-4, 315-5 315-6, 316-1 323-1, 323-2 323-3	33	Oil- and coal-fired (various sizes)
Enterprise Power	101-1, 101-2 101-3, 101-4 102-1, 102-2 102-3, 102-4 107-1, 107-2 107-3, 113-1 113-2, 113-3	201-1, 201-2 201-3, 201-4 202-1, 202-2 202-3, 202-4 207-1, 207-2 207-3, 213-1 213-2, 213-3	301-1, 301-2 301-3, 301-4 302-1, 302-2 302-3, 302-4 307-1, 307-2 307-3, 313-1 313-2, 313-3	42	Oil- and coal-fired (various sizes)

Methods: N/A

3.1.1.4 The simulation power grid shall have the following Load-Serving Entities and configuration.

Requirement #: IMGC.0059.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 07/06/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 07/28/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Defines the Load-Serving Entities and how they fit into the simulation power grid. Interruptible loads are defined for selected buses. The amount of load that can be interrupted is defined as a fraction of the forecast load on the bus for the current hour.

Bounds/Range: N/A

Active during: Always

Source(s): Extension to [IEEE RTS96]

Format: see Table 2

Table 2 - Load-Serving Entities

Load-Serving Entity Name	Control Area	Buses	Interruptible load buses	Interruptible load fraction
Iris	Applewood	101, 102, 104, 105, 106, 107, 108	108	0.30
Jasmine	Applewood	103, 115, 117, 118, 121, 122, 124	103, 115	0.25, 0.25
Kumquat	Applewood	109, 110, 111, 112, 113	109, 113	0.3, 0.4
Lilac	Applewood	114, 116, 119, 120, 123		
Maple	Beech	201, 202, 204, 205, 206, 207, 208	208	0.30
Nut	Beech	203, 215, 217, 218, 221, 222, 224	203, 215	0.25, 0.25
Oak	Beech	209, 210, 211, 212, 213	209, 213	0.3, 0.4
Peach	Beech	214, 216, 219, 220, 223		
Quince	Cherry	301, 302, 304, 305, 306, 307, 308	308	0.30
Rose	Cherry	303, 315, 317, 318, 321, 322, 324	303, 315	0.25, 0.25
Sumac	Cherry	309, 310, 311, 312, 313	309, 313	0.3, 0.4
Teak	Cherry	314, 316, 319, 320, 323, 325		

Methods: N/A

3.1.1.5 The simulation power grid shall have the following buses, bus loads, and configuration.

Requirement #: IMGC.0060.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 07/06/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/07/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Defines the buses, annual peak bus loads, and how they fit into the simulation power grid. Note that some buses have no loads either because they are a generator only bus or they are in the same substation with another load bus. Only real power values are used in the simulation.

Bounds/Range: N/A

Active during: Always

Source(s): IEEE-RTS96

Format: see Table 3.

Table 3 - IEEE RTS-96 Bus Data (3 Areas) [IEEE-RTS96]

BUS #	BUS NAME	BUS TYPE	MW LOAD	MVAR LOAD	BL	Base kV
101	Abel	2	108	22	0	138
102	Adams	2	97	20	0	138
103	Adler	1	180	37	0	138
104	Agricola	1	74	15	0	138
105	Aiken	1	71	14	0	138
106	Alber	1	136	28	-1.00	138
107	Alder	2	125	25	0	138
108	Alger	1	171	35	0	138
109	Ali	1	175	36	0	138
110	Allen	1	195	40	0	138
111	Anna	1	0	0	0	230
112	Archer	1	0	0	0	230
113	Arne	3	265	54	0	230
114	Arnold	2	194	39	0	230
115	Arthur	2	317	64	0	230
116	Asser	2	100	20	0	230
117	Aston	1	0	0	0	230
118	Astor	2	333	68	0	230
119	Attar	1	181	37	0	230
120	Attila	1	128	26	0	230
121	Attlee	2	0	0	0	230
122	Aubrey	2	0	0	0	230
123	Austen	2	0	0	0	230
124	Avery	1	0	0	0	230
201	Bach	2	108	22	0	138
202	Bacon	2	97	20	0	138
203	Baffin	1	180	37	0	138
204	Bailey	1	74	15	0	138
205	Bain	1	71	14	0	138
206	Bajer	1	136	28	-1.00	138
207	Baker	2	125	25	0	138
208	Balch	1	171	35	0	138
209	Balzac	1	175	36	0	138
210	Banks	1	195	40	0	138
211	Bardeen	1	0	0	0	230
212	Barkla	1	0	0	0	230
213	Barlow	2	265	54	0	230
214	Barry	2	194	39	0	230
215	Barton	2	317	64	0	230
216	Basov	2	100	20	0	230
217	Bates	1	0	0	0	230
218	Bayle	2	333	68	0	230
219	Bede	1	181	37	0	230
220	Beethoven	1	128	26	0	230
221	Behring	2	0	0	0	230

BUS #	BUS NAME	BUS TYPE	MW LOAD	MVAR LOAD	BL	Base kV
222	Bell	2	0	0	0	230
223	Bloch	2	0	0	0	230
224	Bordet	1	0	0	0	230
301	Cabell	2	108	22	0	138
302	Cabot	2	97	20	0	138
303	Caesar	1	180	37	0	138
304	Caine	1	74	15	0	138
305	Calvin	1	71	14	0	138
306	Camus	1	136	28	-1.00	138
307	Carew	2	125	25	0	138
308	Carrel	1	171	35	0	138
309	Carter	1	175	36	0	138
310	Caruso	1	195	40	0	138
311	Cary	1	0	0	0	230
312	Caxton	1	0	0	0	230
313	Cecil	2	265	54	0	230
314	Chain	2	194	39	0	230
315	Chase	2	317	64	0	230
316	Chifa	2	100	20	0	230
317	Chuhsi	1	0	0	0	230
318	Clark	2	333	68	0	230
319	Clay	1	181	37	0	230
320	Clive	1	128	26	0	230
321	Cobb	2	0	0	0	230
322	Cole	2	0	0	0	230
323	Comte	2	0	0	0	230
324	Curie	1	0	0	0	230
325	Curtiss	1	0	0	0	230

100 numbered buses are in the Applewood Control Area.
200 numbered buses are in the Beech Control Area.
300 numbered buses are in the Cherry Control Area.
Bus Type:

- 1 - Load Bus (no generation).
- 2 - generator or plant bus.
- 3 - swing bus.

MW Load: load real power to be held constant for power-flow analysis base case.
MVAR Load: load reactive power to be held constant for power-flow analysis base case.
BL: imaginary component of shunt admittance to ground.

Methods: N/A

3.1.2 Attribute Requirements

3.1.2.1 Overall context

Figure 16 shows the Class Diagram for the Simulation Power Grid.

3.1.2.2 Security Coordinator Attributes

Figure 18 shows the attributes and methods of the Security Coordinator class.

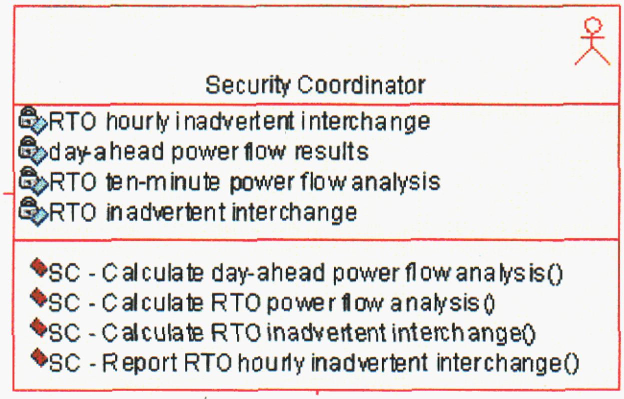


Figure 18 - Security Coordinator Class

3.1.2.2.1 RTO hourly inadvertent interchange

Requirement #: IMGC.0061.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/12/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Report hourly accumulated inadvertent interchange to each Control Area.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: Pair of Control Area names, date/time, hourly inadvertent interchange in MWh.

3.1.2.2.2 day-ahead power flow results

Requirement #: IMGC.0002.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish DC power flows for the entire network for each hour of the day-ahead schedule. Results are used to identify transmission line overloads.

Bounds/Range: Transmission line overloads are reported at 85% of transmission line continuous rating during the planning phase.

Active during: Planning Phase

Source(s): N/A

Format:
The results of the DC power flow analysis for each bus for each hour is the angle of the bus. The results for each transmission line for each hour is the power flow in the line. The results are organized by Control Area.

Methods: N/A

3.1.2.2.3 RTO-ten-minute power flow results

Requirement #: IMGC.0004.004	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish DC power flows for the entire network each ten minutes during real-time operations. Results are used to identify transmission line overloads.

Bounds/Range: Transmission line overloads are reported at 100% of transmission line continuous rating during the real-time operations phase.

Active during: RTO Phase

Source(s): N/A

Format:
The results of the DC power flow analysis for each bus for each hour is the angle of the bus. The results for each transmission line for each hour is the power flow in the line.

Methods: N/A

3.1.2.2.4 RTO inadvertent interchange

Requirement #: IMGC.0064.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/13/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/13/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Calculate inadvertent interchange for each Control Area each ten minutes. The accumulated inadvertent interchange is reported to each Control Area at the top of each hour.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format:
Pair of Control Area names, date/time, inadvertent interchange in MWh.

Methods: N/A

3.1.2.3 Control Area Operator Attributes

Figure 19 shows the attributes and methods of the Control Area Operator class.

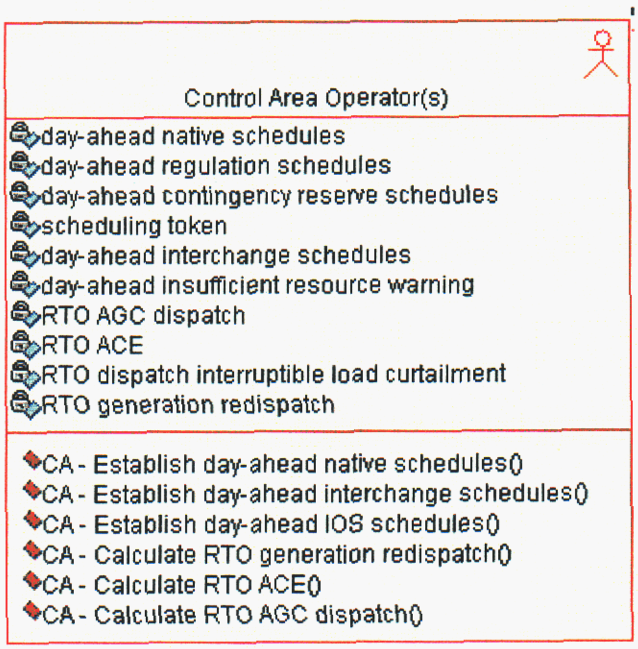


Figure 19 - Control Area Operator Class

3.1.2.3.1 day-ahead native schedules

Requirement #: IMGC.0005.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Allocating native generation resources to supply native loads within a Control Area during state 1 and stage 2 of the scheduling process.

Bounds/Range: No more than 70% of any generator unit may be scheduled during stage 1. No more than an additional 10% of any generator unit may be scheduled during each round of stage 2 of the scheduling process.

Active during: Planning Phase

Source(s): N/A

Format:
Native schedule for a Control Area by hour listing generator unit ID and power in MW.

Methods: N/A

3.1.2.3.2 day-ahead regulation schedules

Requirement #: IMGC.0006.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Allocating native generation resources to be available to supply native loads that exceed the forecast loads during real-time operations. Regulation schedules are formed for each hour. Regulation schedules are formed during the fifth stage of the scheduling process after all native schedules and interchange schedules are completed.

Bounds/Range: Regulation schedules are set at 15% of the total forecast loads for a Control Area.

Active during: Planning Phase

Source(s): N/A

Format: Regulation schedule for a Control Area by hour listing generator unit ID and power in MW.

Methods: N/A

3.1.2.3.3 day-ahead contingency reserve schedules

Requirement #: IMGC.0007.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Allocating native generation resources to be available to supply native loads that exceed the forecast loads and regulation services during real-time operations. Contingency reserve schedules are formed for each Control Area for each hour. Contingency reserve schedules are formed as the fifth stage of the scheduling process after regulation schedules are completed.

Bounds/Range: Contingency reserve schedules are set to the greater of 10% of the total forecast loads for a Control Area or the scheduled power from the largest generation unit in the Control Area.

Active during: Planning Phase

Source(s): N/A

Format: Contingency reserve schedule for a Control Area by hour listing generator unit ID and power in MW.

Methods: N/A

3.1.2.3.4 scheduling token

Requirement #: IMGC.0009.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Providing coordination among Control Areas during interchange scheduling, stage 2 of the scheduling process.

Bounds/Range: Only the single Control Area with the token is allowed to form interchange schedules.

Active during: Planning Phase

Source(s): N/A

Format: The scheduling token is a software mechanism that depends on the software implementation design.

Methods: N/A

3.1.2.3.5 day-ahead interchange schedules

Requirement #: IMGC.0010.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Allocating generation resources from any Control Area to supply native loads. Interchange schedules are formed for each hour during stage 3 of the scheduling process.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): Only the Control Area with the scheduling token can form interchange schedules. No more than 10% of the total capacity of any generator unit can be scheduled by a Control Area during one round of interchange scheduling.

Format: Interchange schedules for a Control Area by hour listing generator unit ID and power in MW.

Methods: N/A

3.1.2.3.6 day-ahead insufficient resource warning

Requirement #: IMGC.0011.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Display to Control Area operator if the scheduling process fails to complete scheduling due to insufficient resources. Detection of insufficient resources can occur during interchange scheduling, stage 3, or regulation and contingency reserve scheduling, stage 5, of the scheduling process.

Bounds/Range: The model does not have any mechanism to resolve insufficient resources conditions during the planning phase.

Active during: Planning Phase

Source(s): N/A

Format: Insufficient resources warnings list the Control Area name, date/time, which scheduling type was terminated, and the power requirement that remained to be scheduled in MW.

Methods: N/A

3.1.2.3.7 RTO AGC dispatch

Requirement #: IMGC.0016.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Command generation units to change power output for the next minute. AGC dispatch is the increment of generation, whether positive or negative, that corrects the generation-load balance. The generation-load balance occurs because the actual load and the generation dispatched the previous minute usually do not match.

Bounds/Range: AGC dispatch does not apply to generator units operating in setpoint mode.

Active during: RTO Phase

Source(s): N/A

Format: Command generation units to change power output for the next minute. AGC dispatch is the increment of generation, whether positive or negative, that corrects the generation-load balance.

Methods: N/A

3.1.2.3.8 RTO ACE

Requirement #: IMGC.0018.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Report Area Control Error (ACE) to the Security Coordinator every ten minutes.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: Control Area name, date/time, ACE in MW.

Methods: N/A

3.1.2.3.9 RTO dispatch interruptible load curtailment

Requirement #: IMGC.0020.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Command Load-Serving Entities to curtail interruptible load when all other generation resources are exhausted in a Control Area.

Bounds/Range: Limited to the day-ahead interruptible load forecast provided by each Load-Serving Entity during the planning phase.

Active during: RTO Phase

Source(s): N/A

Format: Load-Serving Entity name, date/time, bus ID, load curtailment in MW.

Methods: N/A

3.1.2.3.10 RTO generation redispatch

Requirement #: IMGC.0013.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Command generation units to change power output for the ten minutes. Generation redispatch is the increment of generation, whether positive or negative, that corrects for changes in load between forecast load points. Generation redispatch considers the merit-order of generation resources.

Bounds/Range: Generation redispatch does not apply to generator units operating in setpoint mode when other generator units are providing power in AGC mode.

Active during: RTO Phase

Source(s): N/A

Format: Command generation units to change power output for the next minute. AGC dispatch is the increment of generation, whether positive or negative, that corrects the generation-load balance.

Methods: N/A

3.1.2.4 Transmission Service Provider Attributes

Figure 20 shows the attributes and methods of the Transmission Service Provider class.

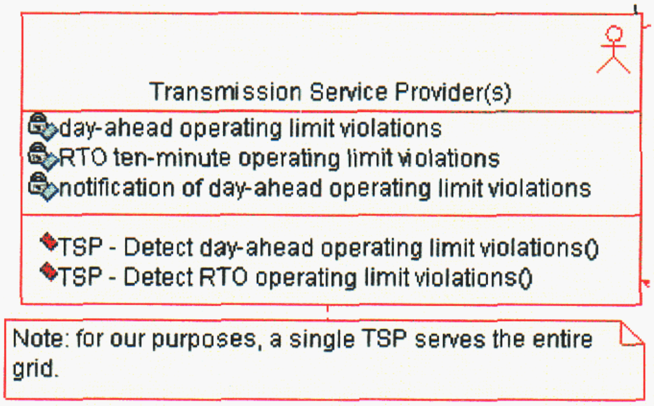


Figure 20 - Transmission Service Provider Class

3.1.2.4.1 day-ahead operating limit violations

Requirement #: IMGC.0021.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/07/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Warn Control Areas of potential transmission congestion that may need operator intervention and adjustments to schedules.

Bounds/Range: Transmission line overloads are identified at 85% of continuous rating of transmission line.

Active during: Planning Phase

Source(s): N/A

Format: Transmission line ID, line capacity, forecast power flow, percent of forecast power flow/line capacity.

Methods: N/A

3.1.2.4.2 RTO-ten minute operating limit violations

Requirement #: IMGC.0022.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/07/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Warn Control Areas of transmission line overload conditions. This is the basis for curtailment of interruptible loads.

Bounds/Range: Transmission line overloads are identified at 100% of continuous rating of transmission line.

Active during: RTO Phase

Source(s): N/A

Format: Transmission line ID, line capacity, forecast power flow, percent of forecast power flow/line capacity.

Methods: N/A

3.1.2.5 Grid Model Attributes

Figure 21 shows the attributes of the Grid Model class.

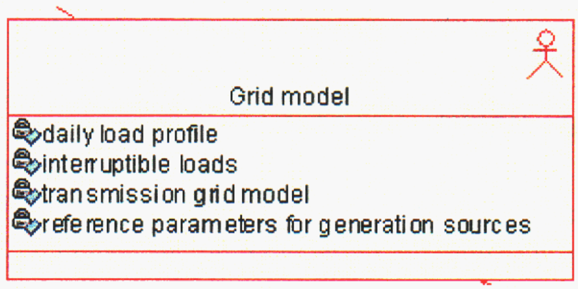


Figure 21 - Grid Model Class

3.1.2.5.1 daily load profile

Requirement #: IMGC.0023.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 07/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish load forecast for each hour of the day.

Bounds/Range: Annual peak load for each Control Area is 2850 MW and 580 MVAR.

Active during: Planning Phase

Source(s): IEEE-RTS96, Tables 2,3 and 4.

Format: Refer to Table 4, Table 5, and Table 6.

Methods: N/A

Table 4 - Weekly Peak Load in Percent of Annual Peak [IEEE-RTS96]

Week	Peak Load	Week	Peak Load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4

Week	Peak Load	Week	Peak Load
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

Table 5 - Daily Load in Percent of Weekly Peak [IEEE-RTS96]

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table 6 - Hourly Peak Load in Percent of Daily Peak [IEEE-RTS96]

	winter weeks 1 -8 & 44 - 52		summer weeks 18 -30		spring/fall weeks 9-17 & 31 - 43	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
12-1 am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68

	winter weeks 1 -8 & 44 - 52		summer weeks 18 -30		spring/fall weeks 9-17 & 31 - 43	
Hour	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
12-1 am	67	78	64	74	63	75
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

3.1.2.5.2 interruptible loads

Requirement #: IMGC.0024.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 07/28/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Reducing load at selected buses when insufficient generation is available for dispatch to provide for actual load during real-time operations.

Bounds/Range: Interruptible loads are 25 to 40 percent of the forecast loads on selected buses.

Active during: Planning Phase

Source(s): N/A

Format: Refer to Table 2.

Methods: N/A

3.1.2.5.3 transmission grid model

Requirement #: IMGC.0025.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/07/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Calculating DC power flow in simulation power grid

Bounds/Range: Power flow is calculated for the three Control Areas, not each Control Area separately. Only the transmission line reactance is used in the power flow calculation.

Active during: Always

Source(s): IEEE-RTS96, Table 12

Format: Refer to Table 7.

Methods: N/A

Table 7 - Transmission Line Data for Simulation Power Grid [IEEE-RTS96]

ID #	From	To	L	R pu	X pu	B pu	Con	LTE	STE	Tr pu
A1	101	102	3	0.003	0.014	0.461	175	193	200	0
A2	101	103	55	0.055	0.211	0.057	175	208	220	0
A3	101	105	22	0.022	0.085	0.023	175	208	220	0
A4	102	104	33	0.033	0.127	0.034	175	208	220	0
A5	102	106	50	0.050	0.192	0.052	175	208	220	0
A6	103	109	31	0.031	0.119	0.032	175	208	220	0
A7	103	124	0	0.002	0.084	0	400	510	600	1.015
A8	104	109	27	0.027	0.104	0.028	175	208	220	0
A9	105	110	23	0.023	0.088	0.024	175	208	220	0
A10	106	110	16	0.014	0.061	2.459	175	193	200	0
A11	107	108	16	0.016	0.061	0.017	175	208	220	0
AB1	107	203	42	0.042	0.161	0.044	175	208	220	0
A12-1	108	109	43	0.043	0.165	0.045	175	208	220	0
A13-2	108	110	43	0.043	0.165	0.045	175	208	220	0
A14	109	111	0	0.002	0.084	0	400	510	600	1.03
A15	109	112	0	0.002	0.084	0	400	510	600	1.03
A16	110	111	0	0.002	0.084	0	400	510	600	1.015
A17	110	112	0	0.002	0.084	0	400	510	600	1.015
A18	111	113	33	0.006	0.048	0.100	500	600	625	0
A19	111	114	29	0.005	0.042	0.088	500	600	625	0
A20	112	113	33	0.006	0.048	0.100	500	600	625	0
A21	112	123	67	0.012	0.097	0.203	500	600	625	0
A22	113	123	60	0.011	0.087	0.182	500	600	625	0
AB2	113	215	52	0.010	0.075	0.158	500	600	625	0
A23	114	116	27	0.005	0.059	0.082	500	600	625	0
A24	115	116	12	0.002	0.017	0.036	500	600	625	0
A25-1	115	121	34	0.006	0.049	0.103	500	600	625	0
A25-2	115	121	34	0.006	0.049	0.103	500	600	625	0
A26	115	124	36	0.007	0.052	0.109	500	600	625	0
A27	116	117	18	0.003	0.026	0.055	500	600	625	0
A28	116	119	16	0.003	0.023	0.049	500	600	625	0
A29	117	118	10	0.002	0.014	0.030	500	600	625	0
A30	117	122	73	0.014	0.105	0.221	500	600	625	0

ID #	From	To	L	R pu	X pu	B pu	Con	LTE	STE	Tr pu
C33-2	320	323	15	0.003	0.022	0.046	500	600	625	0
C34	321	322	47	0.009	0.068	0.142	500	600	625	0
CA-1	325	121	67	0.012	0.097	0.203	500	600	625	0
CB-1	318	223	72	0.013	0.104	0.218	500	600	625	0
C35	323	325	0	0.000	0.009	0	722	893	893	1.00

ID# = Branch identifier.

- Inter area branches are indicated by double letter ID.
- Circuits on a common tower have hyphenated ID#.

R, X, and B = Transmission line impedance
All per unit quantities are on 100 MVA base.
Con = Continuous rating.
LTE = Long-time emergency rating (24 hour).
STE = Short-time emergency rating (15 minute).
Tr = Transformer off-nominal ratio.

- Transformer branches are indicated by Tr ≠ 0.

The circuits which have common Right-Of-Way (ROW) or Common Structure (CS) are indicated by loops lettered A - G in the one-line diagrams, the common lengths (miles) are as follows:
A - 45 (ROW), B - 15 (CS), C - 18 (CS), D - 34 (ROW), E - 33 (CS), F - 43 (CS), G - 19 (CS).

3.1.2.5.4 reference parameters for generation sources

Requirement #: IMGC.0026.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 08/07/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Calculating power flow in simulation power grid and preparing generation plan

Bounds/Range: Some generator units are not available during annual maintenance periods.

Active during: Planning Phase

Source(s): IEEE-RTS96, Table 7 and IEEE-RTS-86, Table XI.

Format: Refer to Table 8.

Methods: N/A

Table 8 - Generation Resources at Each Bus

Bus ID	Unit ID#	Unit Type	P^{max} MW	P^{min} MW	Out of service for maintenance (on week #)
101	1	U20	20	15.80	9-10
101	2	U20	20	15.80	12-13
101	3	U76	76	15.20	3-5
101	4	U76	76	15.20	30-32
102	1	U20	20	15.80	12-13
102	2	U20	20	15.80	33-34
102	3	U76	76	15.20	15-17
102	4	U76	76	15.20	34-36
107	1	U100	100	25.00	20-22
107	2	U100	100	25.00	27-29
107	3	U100	100	25.00	41-43

Bus ID	Unit ID#	Unit Type	P^{max} MW	P^{min} MW	Out of service for maintenance (on week #)
113	1	U197	197	68.95	8-11
113	2	U197	197	68.95	15-18
113	3	U197	197	68.95	40-43
115	1	U12	12	2.40	9-10
115	2	U12	12	2.40	26-27
115	3	U12	12	2.40	33-34
115	4	U12	12	2.40	38-39
115	5	U12	12	2.40	41-42
115	6	U155	155	54.25	6-9
116	1	U155	155	54.25	26-29
118	1	U400	400	100.00	10-15
121	1	U400	400	100.00	35-40
122	1	U50	50	2.50	16-17
122	2	U50	50	2.50	21-22
122	3	U50	50	2.50	27-28
122	4	U50	50	2.50	31-32
122	5	U50	50	2.50	38-39
122	6	U50	50	2.50	41-42
123	1	U155	155	54.25	11-14
123	2	U155	155	54.25	36-39
123	3	U350	350	140.00	31-35
201	1	U20	20	15.80	9-10
201	2	U20	20	15.80	12-13
201	3	U76	76	15.20	3-5
201	4	U76	76	15.20	30-32
202	1	U20	20	15.80	12-13
202	2	U20	20	15.80	33-34
202	3	U76	76	15.20	15-17
202	4	U76	76	15.20	34-36
207	1	U100	100	25.00	20-22
207	2	U100	100	25.00	27-29
207	3	U100	100	25.00	41-43
213	1	U197	197	68.95	8-11
213	2	U197	197	68.95	15-18
213	3	U197	197	68.95	40-43

Bus ID	Unit ID#	Unit Type	P^{max} MW	P^{min} MW	Out of service for maintenance (on week #)
215	1	U12	12	2.40	9-10
215	2	U12	12	2.40	26-27
215	3	U12	12	2.40	33-34
215	4	U12	12	2.40	38-39
215	5	U12	12	2.40	41-42
215	6	U155	155	54.25	6-9
216	1	U155	155	54.25	26-29
218	1	U400	400	100.00	10-15
221	1	U400	400	100.00	35-40
222	1	U50	50	2.50	16-17
222	2	U50	50	2.50	21-22
222	3	U50	50	2.50	27-28
222	4	U50	50	2.50	31-32
222	5	U50	50	2.50	38-39
222	6	U50	50	2.50	41-42
223	1	U155	155	54.25	11-14
223	2	U155	155	54.25	36-39
223	3	U350	350	140.00	31-35
301	1	U20	20	15.80	9-10
301	2	U20	20	15.80	12-13
301	3	U76	76	15.20	3-5
301	4	U76	76	15.20	30-32
302	1	U20	20	15.80	12-13
302	2	U20	20	15.80	33-34
302	3	U76	76	15.20	15-17
302	4	U76	76	15.20	34-36
307	1	U100	100	25.00	20-22
307	2	U100	100	25.00	27-29
307	3	U100	100	25.00	41-43
313	1	U197	197	68.95	8-11
313	2	U197	197	68.95	15-18
313	3	U197	197	68.95	40-43
315	1	U12	12	2.40	9-10
315	2	U12	12	2.40	26-27
315	3	U12	12	2.40	33-34

Bus ID	Unit ID#	Unit Type	P ^{max} MW	P ^{min} MW	Out of service for maintenance (on week #)
315	4	U12	12	2.40	38-39
315	5	U12	12	2.40	41-42
315	6	U155	155	54.25	6-9
316	1	U155	155	54.25	26-29
318	1	U400	400	100.00	10-15
321	1	U400	400	100.00	35-40
322	1	U50	50	2.50	16-17
322	2	U50	50	2.50	21-22
322	3	U50	50	2.50	27-28
322	4	U50	50	2.50	31-32
322	5	U50	50	2.50	38-39
322	6	U50	50	2.50	41-42
323	1	U155	155	54.25	11-14
323	2	U155	155	54.25	36-39
323	3	U350	350	140.00	31-35

3.1.2.6 Generator Attributes

Figure 22 shows the attributes and methods of the Generator class.

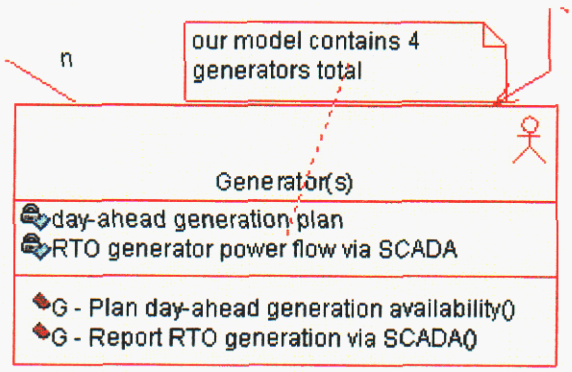


Figure 22 - Generator Class

3.1.2.6.1 day-ahead generation plan

Requirement #: IMGC.0027.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 07/28/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish day-ahead generation plan for each of the three Control Areas by each of the four Generator entities.

Bounds/Range: All generation resources area available for scheduling except for those units that are out of service for annual maintenance as indicated in Table 8.

Active during: Planning Phase

Source(s): Extension to IEEE-RTS96

Format:

For each Generator entity the generation plan includes generator unit ID, composed of Bus ID and Unit ID# as shown in Table 8.

Each generation plan specifies real power capacity in MW and nominal voltage in per unit.

Generation plan lists by hour the available power capability, and contingency reserve capability, if it is designated separately, to be available for scheduling for each generator unit.

Merit-order generation dispatch is shown in Table 9.

Methods: N/A

Table 9 - Merit-Order Dispatch for Generation Resources

Applewood CA Generator ID	Beech CA Generator ID	Cherry CA Generator ID	Unit Group	Unit Type	Unit Size (MW)	AGC Mode
118-1	218-1	318-1	U400	Nuclear	400	Setpoint
121-1	221-1	321-1	U400	Nuclear	400	Setpoint
123-3	223-3	323-3	U350	Coal/Steam	350	Setpoint
122-1	222-1	322-1	U50	Hydro	50	AGC
122-2	222-2	322-2	U50	Hydro	50	AGC
122-3	222-3	322-3	U50	Hydro	50	AGC
122-4	222-4	322-4	U50	Hydro	50	AGC
122-5	222-5	322-5	U50	Hydro	50	AGC
122-6	222-6	322-6	U50	Hydro	50	AGC
107-1	207-1	307-1	U100	Oil/Steam	100	AGC
123-1	223-1	323-1	U155	Coal/Steam	155	AGC
101-3	201-3	301-3	U76	Coal/Steam	76	AGC
102-3	202-3	302-3	U76	Coal/Steam	76	AGC
115-6	215-6	315-6	U155	Coal/Steam	155	AGC
123-2	223-2	323-2	U155	Coal/Steam	155	AGC
116-1	216-1	316-1	U155	Coal/Steam	155	AGC
101-4	201-4	301-4	U76	Coal/Steam	76	AGC
102-4	202-4	302-4	U76	Coal/Steam	76	AGC
113-1	213-1	313-1	U197	Oil/Steam	197	AGC
113-2	213-2	313-2	U197	Oil/Steam	197	AGC
113-3	213-3	313-3	U197	Oil/Steam	197	AGC
107-2	207-2	307-2	U100	Oil/Steam	100	AGC
107-3	207-3	307-3	U100	Oil/Steam	100	AGC
115-1	215-1	315-1	U12	Oil/Steam	12	AGC
115-2	215-2	315-2	U12	Oil/Steam	12	AGC
115-3	215-3	315-3	U12	Oil/Steam	12	AGC

115-4	215-4	315-4	U12	Oil/Steam	12	AGC
115-5	215-5	315-5	U12	Oil/Steam	12	AGC
101-1	201-1	301-1	U20	Oil/CT	20	AGC
102-1	202-1	302-1	U20	Oil/CT	20	AGC
101-2	201-2	301-2	U20	Oil/CT	20	AGC
102-2	202-2	302-2	U20	Oil/CT	20	AGC

NOTE: Listed in order of decreasing merit.

3.1.2.6.2 RTO generator power flow via SCADA

Requirement #: IMGC.0028.003 Date introduced: 06/21/2000 Date of last change: 09/12/2000	Area: ☒ ACE ☐ IA	Status: ☒ Draft ☐ Accepted	Classification: ☐ UCI ☒ None	Surety rating: ☒ None ☐ Moderate ☐ High

Used for: Report generator power flow via SCADA to each Control Area by each generation entity.

Bounds/Range: Check that reported power flow does not exceed generator unit capacity.

Active during: RTO Phase

Source(s): N/A

Format: Date/time, generator ID, power flow in MW.

Methods: N/A

3.1.2.7 Load-Serving Entity(ies) Attributes

Figure 23 shows the attributes and methods of the Load-Serving Entity class.

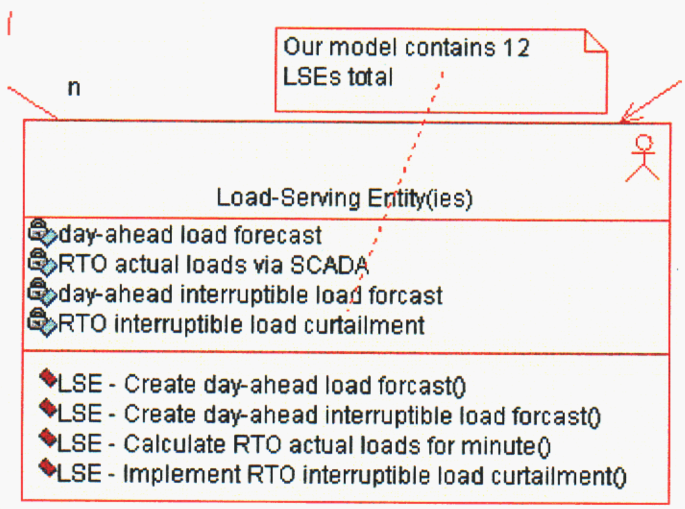


Figure 23 - Load-Serving Entity(ies) Class

3.1.2.7.1 day-ahead load forecast

Requirement #: IMGC.0032.001 Date introduced: 06/21/2000 Date of last change: 06/21/2000	Area: ☒ ACE ☐ IA	Status: ☒ Draft ☐ Accepted	Classification: ☐ UCI ☒ None	Surety rating: ☒ None ☐ Moderate ☐ High

Used for: Establish load forecast for each hour to be used in the day-ahead scheduling process.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): N/A

Format:
listed by hour and bus, for each native load
The load forecast includes real power in MW.

Methods: N/A

3.1.2.7.2 RTO actual loads via SCADA

Requirement #: IMGC.0035.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Report actual loads to Control Area for use in real-time control calculations at one minute intervals.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: For each Load-Serving Entity listed by bus ID and load in MW.

Methods: N/A

3.1.2.7.3 day-ahead interruptible load forecast

Requirement #: IMGC.0033.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establishing quantity of interruptible load that is available for curtailment during real-time operations.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): N/A

Format: Interruptible load for selected buses listed by hour and bus in MW.

Methods: N/A

3.1.2.7.4 RTO interruptible load curtailment

Requirement #: IMGC.0065.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/13/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/13/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Report load curtailment to Control Area, if any, at one-minute intervals.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: For each Load-Serving Entity listed by bus ID and quantity of load curtailed in MW.

Methods: N/A

3.1.3 Method Requirements Context

Figure 24 shows the Level 1 Data Flow Diagram.

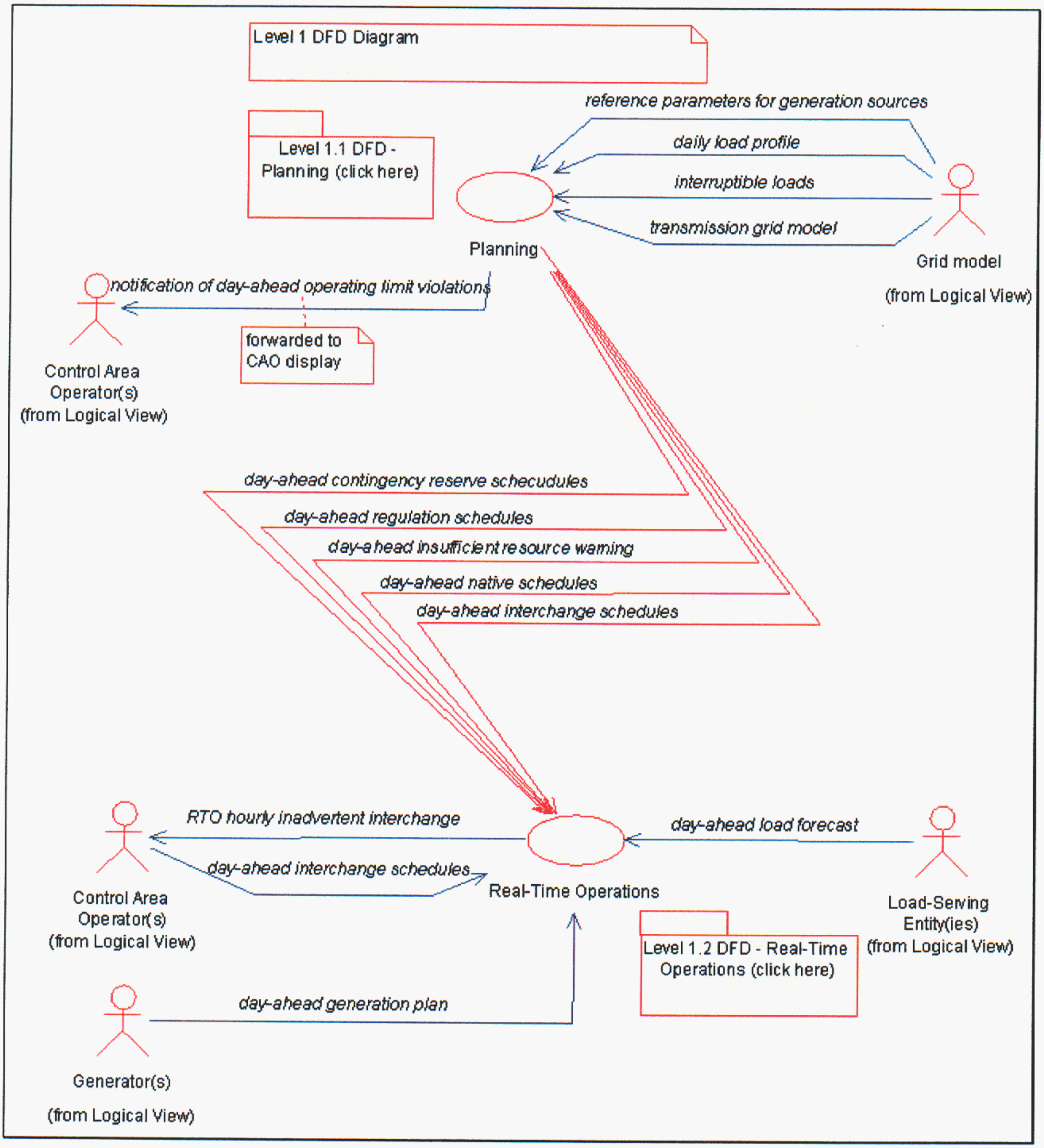


Figure 24 - Data Flow Diagram - Level 1

3.1.4 Planning Phase Method Requirements

3.1.4.1 Planning Phase Context

The planning phase establishes the power grid configuration, generator unit availability, load forecasts, native schedules, and interchange schedules that match generation resources to load forecasts. The planning phase is performed without a time measure so it only represents the way the model establishes the parameters for real-time grid control operations.

The data to be collected to document the simulation results during the planning phase are:

Date and season for plan.
Load forecast for each Load-Serving Entity.
Generation plan for each Generator entity.
Schedules and interchange schedules for power and IOS for each Load-Serving Entity.
Projected transmission overload conditions.
Power flow analysis results.

Figure 25 shows the planning phase Data Flow Diagram.

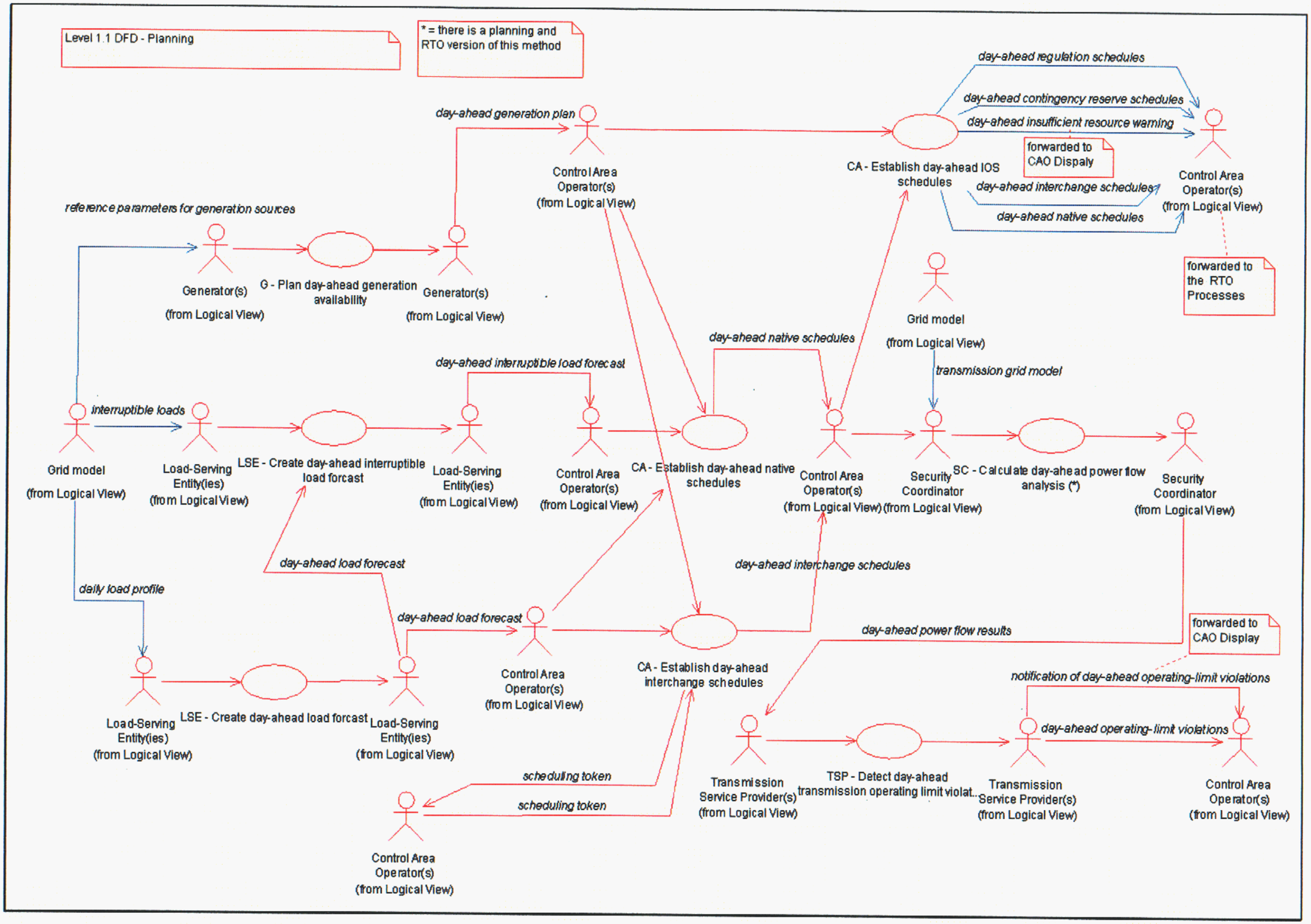


Figure 25 - Planning Phase Data Flow Diagram (Level 1.1)

3.1.4.2 Planning Phase Method Requirements - Specific

3.1.4.2.1 LSE - **Create day-ahead load forecast**

Requirement #: IMGC.0037.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish load forecast for each hour and for each bus owned by Load-Serving Entity by scaling the peak bus load by the factors of weekly load profile, daily load profile, hourly load profile, and seasonal load profile.

Bounds/Range: N/A

Active during: Planning Phase

Source(s):Refer to Tables 3, 4, 5, and 6.

Format: N/A

Methods:

Input: daily load profile
Algorithm:

- Scale the annual peak bus load in Table 3 by the weekly, daily, hourly, and seasonal load profile to obtain a load forecast for each hour and each bus.
- Each Load-Serving Entity sends a load forecast to its Control Area.

Output: day-ahead load forecast

3.1.4.2.2 G - **Plan day-ahead generation availability**

Requirement #: IMGC.0038.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 07/20/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish generation unit availability for the scheduling process.

Bounds/Range: generation units that are out of service for annual maintenance are not available during the weeks shown in Table 8.

Active during: Planning Phase

Source(s): Refer to Table 8.

Format: N/A

Methods:

Input: reference parameters for generation sources
Algorithm:

- Each Generator entity determines which of its generator units are available for the planning date.

Each Generator within a Control Area sends its day-ahead generation plan to the Control Area where the generation units are located.

Output: day-ahead generation plan

3.1.4.2.3 LSE - **Create day-ahead interruptible load forecast**

Requirement #: IMGC.0039.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Establish the interruptible load forecast for each hour of the day to be used during real-time operations if all other available generation is exhausted.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): Refer to Table 2.

Format: N/A

Methods:

Input: day-ahead load forecast
Algorithm:

- Scale the day-ahead load forecast for selected buses by the factors in Table 2 to obtain the interruptible load forecast for each hour.

Output: day-ahead interruptible load forecast

3.1.4.2.4 CA- **Establish day-ahead native schedules**

Requirement #: IMGC.0040.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Each Control Area establishes schedules for the forecast loads within its area from generator units within its area.

Bounds/Range: No more than 70% of any generator unit may be scheduled during stage 1.

Active during: Planning Phase

Source(s): N/A

Format: N/A

Methods:

Input: day-ahead generation plan, day-ahead load forecast
Algorithm:

- This is the first stage of the scheduling process and is repeated for each hour of the day.
- Sum the forecast loads for each bus in the Control Area to obtain the total native load.
- Schedule up to 70% of the highest merit-order generator unit that has not been scheduled. Continue with the next-highest merit-order generator unit until all of the forecast load has been scheduled or all generator units have been scheduled.
- Pass the native schedules to all other Control Areas in preparation for the second stage of the scheduling process.

Output: day-ahead native schedules

3.1.4.2.5 CA - **Establish day-ahead interchange schedules**

Requirement #: IMGC.0041.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Each Control Area establishes interchange schedules between Control Areas and additional native schedules to provide for all remaining native load that was not scheduled during stage 1 of the scheduling process.

Bounds/Range: No more than an additional 10% of any generator unit may be scheduled during each round of stage 2 of the scheduling process.

Active during: Planning Phase

Source(s): N/A

Format: N/A

Methods:

Input: day-ahead generation plan, day-ahead load forecast, scheduling token
Algorithm:

- This is the second stage of the scheduling process and is repeated for each hour of the day.

- This is an iterative process with one Control Area performing scheduling at a time. The Control Areas are arbitrarily assigned sequence numbers for this stage. A scheduling token is passed around among the Control Areas to give control to one to do scheduling.
- Collect the native schedules from all Control Areas. They indicate the remaining generation capacity that is available for scheduling.
- Obtain the scheduling token.
- Schedule up to 10% of the highest merit-order generator unit that has remaining available capacity. Repeat with the next-highest merit-order generator unit until all of the forecast load has been scheduled or all generation units have been scheduled.
- Pass the scheduling token and interchange schedules to the next Control Area in the scheduling sequence.
- The control software provides for more than one round of this scheduling stage to schedule all native load.

Output: day-ahead interchange schedules, scheduling token

3.1.4.2.6 SC - **Calculate day-ahead Power flow analysis**

Requirement #: IMGC.0043.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Perform a DC power flow analysis to determine if transmission lines are overloaded and to calculate the basis for the IOS that must be scheduled. The DC power flow calculates voltage angles for all buses in power system given the net real power injection at each bus. It also calculates all line and transformer flows.

Bounds/Range: All input variables must be available.

Active during: Planning Phase

Source(s): [Stevenson, 1982] pages 214-218. [Wood, 1996] pages 93-111.

Format:

- Input data:
  - Output for every generator in the system at the time of interest for the load flow.
  - Load for every bus in the system at the time of interest for the load flow.
  - Reduced admittance matrix for the system.
  - Swing bus designation and angle
- Output data:
  - Voltage angles for all non-swing buses.
  - Real power flow in each transmission line.
  - Real power flow in each transformer.

Methods:
Input: day-ahead interchange schedules, day-ahead native schedules, transmission grid model
Algorithm:

Things that are done once:

I. Definitions:

A. Construct a mapping to translate the bus # uniquely into an ordered set 1 through N.

B. Let N be the number of buses in a power system.

C. Let M be the number of lines in a power system.

D. Let T be the number of transformers in a power system.

E. Let δ_i be the voltage angle at bus i in the system.

F. Let P_i be the net power injection for bus i in a power system. The net injection for bus i is the generation at i (if there is any, otherwise zero) minus the load at i (if there is any, otherwise zero).

G. Let LF_i be the real power flow in line i with directionality defined as commencing at the "from bus" (denoted as x) and terminating at the "to bus" (denoted as y).

H. Let TF_i be the real power flow in transformer i with directionality defined as commencing at the "from bus" (denoted as x) and terminating at the "to bus" (denoted as y).

I. Let k be the bus number of the swing bus.

II. Initial Setup:

A. Let vector $\delta = [\delta_i]\ \forall\ i \neq k$. Elements of δ are arranged according to from the lowest non-swing bus index to the largest non-swing bus index. The length of δ is N-1.

B. Let B be the $N \times N$ admittance matrix for the system. Furthermore, let B' be the N-1$\times N$-1 reduced admittance matrix for the system.

C. To set up B, start with an $N \times N$ matrix of zeros. Then, for each line in the system:

1. Extract the "from bus" parameter x, "to bus" parameter as y, resistance as R, and reactance as X
2. Assign: $B_{xx} = B_{xx} + \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
3. Assign: $B_{yy} = B_{yy} + \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
4. Assign: $B_{xy} = B_{xy} - \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
5. Assign: $B_{yx} = B_{yx} - \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$

D. And for each transformer in the system:

1. Extract the "from bus" parameter x, "to bus" parameter as y, resistance as R, reactance as X, and the tap ratio as t
2. Assign: $B_{xx} = B_{xx} + 1/t^2 \cdot \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
3. Assign: $B_{yy} = B_{yy} + \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
4. Assign: $B_{xy} = B_{xy} - 1/t \cdot \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$
5. Assign: $B_{yx} = B_{yx} - 1/t \cdot \mathrm{Im}\ \{1/(R + \mathrm{j}X)\}$

E. For each bus in the system, let the bus parameter be x, then assign $B_{xx} = B_{xx} + B_L$

F. Phase-shifting effects are not considered in the DC load flow.

G. Form B' by deleting (not zeroing - remove it entirely) row k in B. Do the same for column k in B. B is no longer useful, and may be deleted to reduce memory commitments.

H. Form $(B')^{-1}$.

Things that are done each time the load flow is calculated:

I. Let vector $P = [P_i]\ \forall\ i \neq k$. Elements of P are arranged according to from the lowest non-swing bus index to the largest non-swing bus index. The length of P is N-1.

II. Calculate angles for all non-swing buses using:

$\delta = (B')^{-1} \cdot P$

III. For each line i:

$LF_i = (\delta_x - \delta_y)/X$

IV. For each transformer i:

$TF_i = (\delta_x - \delta_y)/X$

- The Security Coordinator assembles schedules from all Control Areas and delete duplications from interchange schedules.
- The results of the analysis are power flow in each transmission line.
- The Security Coordinator sends the results to the Transmission Service Provider and the results that are applicable to each Control Area.

Output: day-ahead power flow results

3.1.4.2.7 CA - **Establish day-ahead IOS schedules**

Requirement #: IMGC.0044.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Each Control Area establishes schedules for regulation and contingency reserve services from generator units within its Control Area.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): N/A

Format: N/A

Methods:

Input: day-ahead generation plan, day-ahead native schedules, day-ahead interchange schedules

Algorithm:

- This is the fifth stage of the scheduling process and is repeated for each hour of the day.
  - The amount of regulation services that are scheduled is 15% of the total native load for the Control Area.
  - Schedule the remaining capacity from the highest merit-order generator unit as needed to reach the required amount of regulation service. Continue with the next-highest merit-order generator unit until the required amount is scheduled.
  - The amount of contingency reserve services that are schedules is the greater of 10% of the total native load or the largest amount of scheduled generation from any generator unit in the Control Area.
- Schedule the remaining capacity from the highest merit-order generator unit as needed to reach the required amount of contingency reserve services.
  - If there is not sufficient generation capacity to meet the regulation or contingency reserve requirements, display a day-ahead insufficient resource warning to the Control Area operator.
  -

Output: day-ahead regulation schedules, day-ahead contingency reserve schedules, day-ahead insufficient resource warning, day-ahead interchange schedules, day-ahead native schedules

3.1.4.2.8 TSP - **Detect day-ahead operating limit violations**

Requirement #: IMGC.0045.003	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Identify schedules that may result in transmission line overloads.

Bounds/Range: N/A

Active during: Planning Phase

Source(s): N/A

Format: N/A

Methods:

Input: day-ahead power flow results

Algorithm:

- Transmission Service Provider compares the power flow predictions with the operating limits for each transmission line. Any locations where the predicted power flow is more than 85% of the operating limit (called an overload) is identified as a day-ahead operating limit violation and sent to the appropriate Control Area operator. The operating limit for transmission lines and components is the continuous ratings listed in Table 7

Output: day-ahead operating limit violations.

3.1.5 Real-Time Operation (RTO) Phase Method Requirements

3.1.5.1 RTO Phase Context

The real-time operations phase simulates activities at the bulk electric system level. Real-time operations are modeled in a greatly simplified way to focus on information management needed to implement interchange schedules and manage Area Control Error (ACE) during routine operating conditions. The software model only includes a limited number of features of the actual power grid in order to allow the model to be implemented in the time available. Daily and seasonal load profiles and random fluctuations of load are used to introduce dynamic elements into the simulations.

The data to be collected during each real-time operations phase are:

Actual load for each Load-Serving Entity for each one-minute interval.
AGC dispatch for each generator unit for each one-minute interval.
Area Control Error (ACE) for each one-minute interval for each Control Area.
Generation redispatch for each generator unit for each ten-minute interval.
Transmission line overload conditions.

Figure 26 shows the top level Data Flow Diagram for the real-time operation phase.

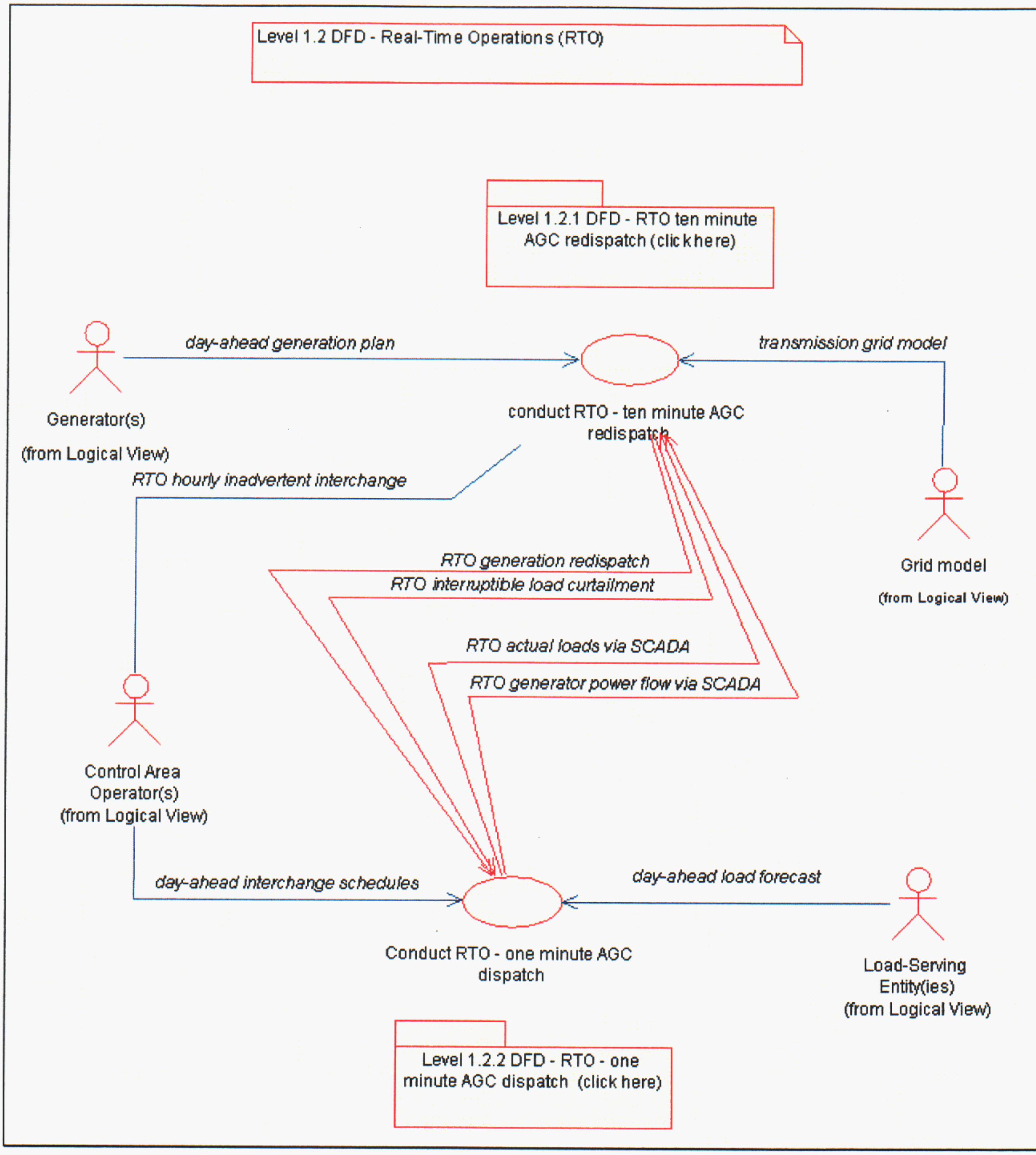


Figure 26 - Real-Time Operation Data Flow Diagram (Level 1.2)

3.1.5.2 RTO Phase Method Requirements - Ten Minute

Figure 27 shows the Ten Minute portion of the real-time operations phase.

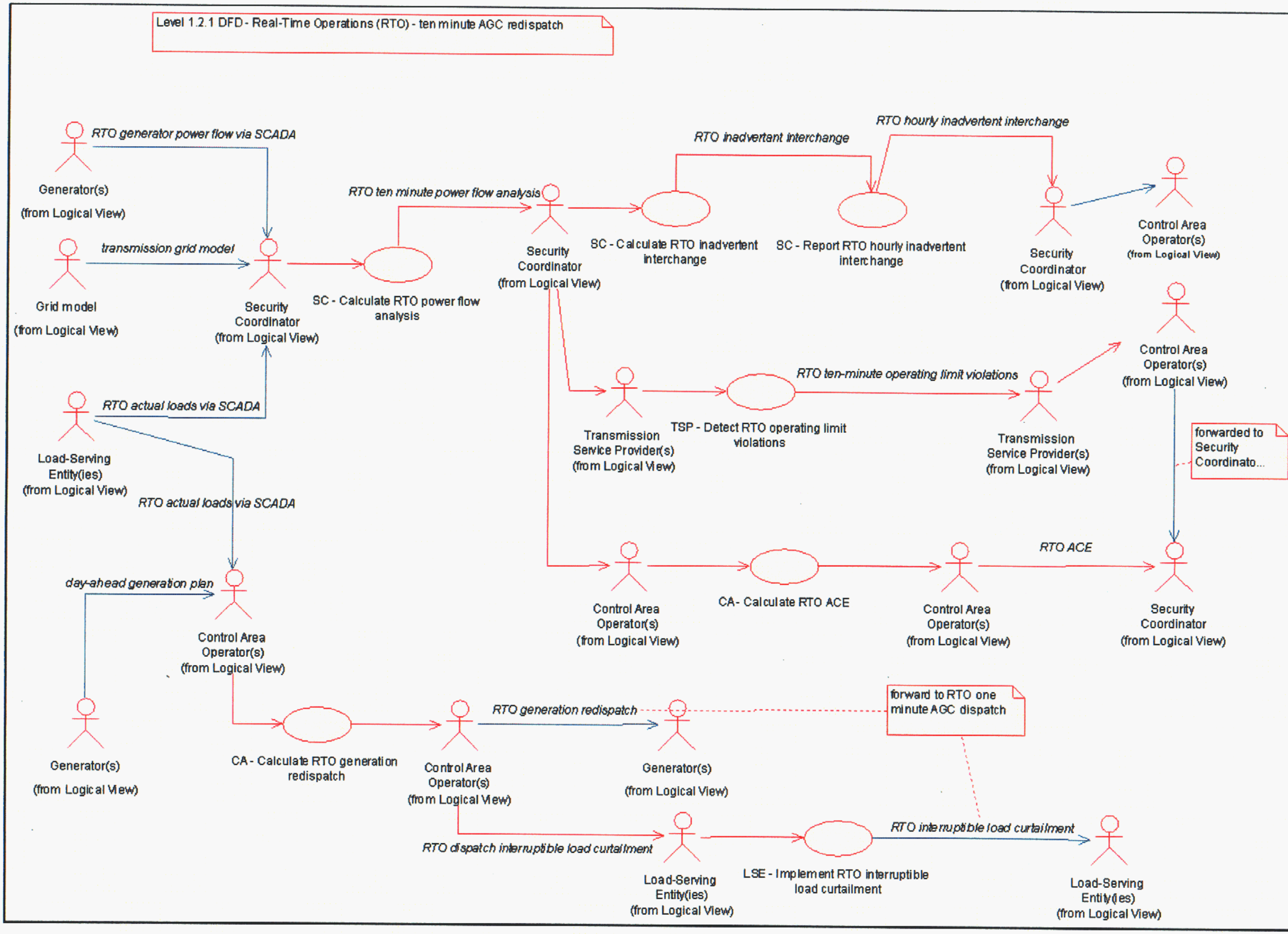


Figure 27 - Ten Minute Real-Time Operation Data Flow Diagram (Level 1.2.1)

3.1.5.2.1 SC - Calculate RTO power flow analysis

Requirement #: IMGC.0049.002 Date introduced: 06/21/2000 Date of last change: 07/13/2000	Area: ☒ ACE ☐ IA	Status: ☒ Draft ☐ Accepted	Classification: ☐UCI ☒None	Surety rating: ☒ None ☐ Moderate ☐ High

Used for: Perform a DC power flow analysis to determine if transmission lines are overloaded with the current real-time operating conditions. The DC power flow calculates voltage angles for all buses in power system given the net real power injection at each bus. It also calculates all line and transformer flows.

Bounds/Range: All input variables must be available.

Active during: RTO Phase

Source(s): [Stevenson, 1982] pages 214-218. [Wood, 1996] pages 93-111.

- **Format**: Input data:
  - Output for every generator in the system at the time of interest for the load flow.
  - Load for every bus in the system at the time of interest for the load flow.
  - Reduced admittance matrix for the system.
  - Swing bus designation and angle
- Output data:
  - Voltage angles for all non-swing buses.
  - Real power flow in each transmission line.
  - Real power flow in each transformer.

Methods:
Input: transmission grid model, RTO generator power flow via SCADA, RTO actual loads via SCADA
Algorithm:

Refer to algorithm in Requirement # IMGC.0043

Output: RTO-ten-minute power flow results

3.1.5.2.2 SC - **Calculate RTO inadvertent interchange**

Requirement #: IMGC.0062.001 Date introduced: 09/12/2000 Date of last change: 09/12/2000	Area: ☒ ACE ☐ IA	Status: ☒ Draft ☐ Accepted	Classification: ☐UCI ☒None	Surety rating: ☒ None ☐ Moderate ☐ High

Used for: Calculates the inadvertent interchange between each pair of Control Areas based on the DC power flow results computed every ten minutes.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:
Input: RTO-ten-minute power flow results
Algorithm:

- Sort the interchange schedules to determine the sum of the interchange schedules between each pair of Control Areas.
- Sum the power flow in the tie lines between each pair of Control Areas to obtain the actual interchange.
- The difference between the scheduled interchange and actual interchange is the inadvertent interchange.

Output: RTO inadvertent interchange

3.1.5.2.3 SC - **Report RTO hourly inadvertent interchange**

Requirement #: IMGC.0063.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/12/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Accumulate the inadvertent interchange for each 10-minute interval to report to each Control Area at the top of each hour.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO inadvertent interchange
Algorithm:

- Slum the inadvertent interchange between each pair of Control Areas for one hour and scale the values to be MWh.
- Report the hourly inadvertent interchange at the top of the hour to each Control Area.

Output: RTO hourly inadvertent interchange

3.1.5.2.4 TSP - **Detect RTO operating limit violations**

Requirement #: IMGC.0050.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Identify transmission line overloads based on real-time power flow results.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO-ten-minute power flow results
Algorithm:

- Transmission Service Provider compares the power flow results with the operating limits for each transmission line. Any locations where the power flow is more than 100% of the operating limit is identified as an operating limit violation and sent to the appropriate Control Area operator. The operating limit for transmission lines and components is the continuous ratings listed in Table 7

Output: RTO-ten minute operating limit violations

3.1.5.2.5 CA - **Calculate RTO generation dispatch**

Requirement #: IMGC.0055.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/12/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Control Area redispatches generator units within its area to match actual loads using the highest merit-order generator units.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO actual loads via SCADA, day-ahead generation plan
Algorithm:

- Determine the imbalance between the hourly generation schedules established during the planning phase and the sum of the SNI and actual load in the Control Area.
- If the imbalance is positive, reduce interruptible load curtailment, if any, then dispatch decreased generation from the lowest merit-order generation units until the imbalance is zero.
- If the imbalance is negative, increase the dispatch of the highest merit-order generator units that are scheduled to provide regulation services.
- If there is inadequate regulations serviced scheduled to zero the imbalance, dispatch contingency reserve services beginning with the highest merit-order generator unit. Whenever contingency reserve services are dispatched, then display a warning to the Control Area operator.
- If there are inadequate contingency reserve services, then dispatch interruptible loads to meet the imbalance.

Output: RTO generation redispatch , RTO dispatch interruptible load curtailment

3.1.5.2.6 CA - **Calculate RTO ACE**

Requirement #: IMGC.0066.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/13/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/13/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Each Control Area calculates ACE at ten-minute intervals.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO-ten-minute power flow results
Algorithm:

- Sum the actual interchange on each tie line with adjacent Control Areas to obtain the net actual interchange.
- Sum the scheduled interchange with each adjacent Control Area to obtain the Net Scheduled Interchange (NSI).
- Calculate ACE as the net actual interchange minus NSI.

Output: RTO ACE

3.1.5.2.7 LSE - **Implement RTO interruptible load curtailment**

Requirement #: IMGC.0067.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 09/13/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/13/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Adjusting the actual load reported be a Load-Serving Entity to implement interruptible load curtailment.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO dispatch interruptible load curtailment
Algorithm:

- Reduce the actual load reported on buses by the amount of the interruptible load curtailment ordered by the Control Area.

Output: RTO interruptible load curtailment

3.1.5.3 RTO Phase Method Requirements - By Minute

Figure 28 shows the by minute portion of the real-time operations phase.

3.1.5.3.1 LSE - **Calculate RTO actual loads for minute**

Requirement #: IMGC.0051.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Provide an actual load for each bus based on hourly load profiles and a random component.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO interruptible load curtailment, day-ahead load forecast
Algorithm:

- Actual loads are calculated for each bus that has a forecast load.
- Each Load-Serving Entity calculates actual loads at each one-minute time step by linearly interpolating between the forecast loads for each hour, which is assumed to apply at the top of each hour. This is adjusted by a random variable from a normal distribution with a standard deviation of ±5% smoothed to approximate a 10-minute time constant. The result is a value that approximates the forecast load values but changes minute by minute with some random variation.

Output: RTO actual loads via SCADA

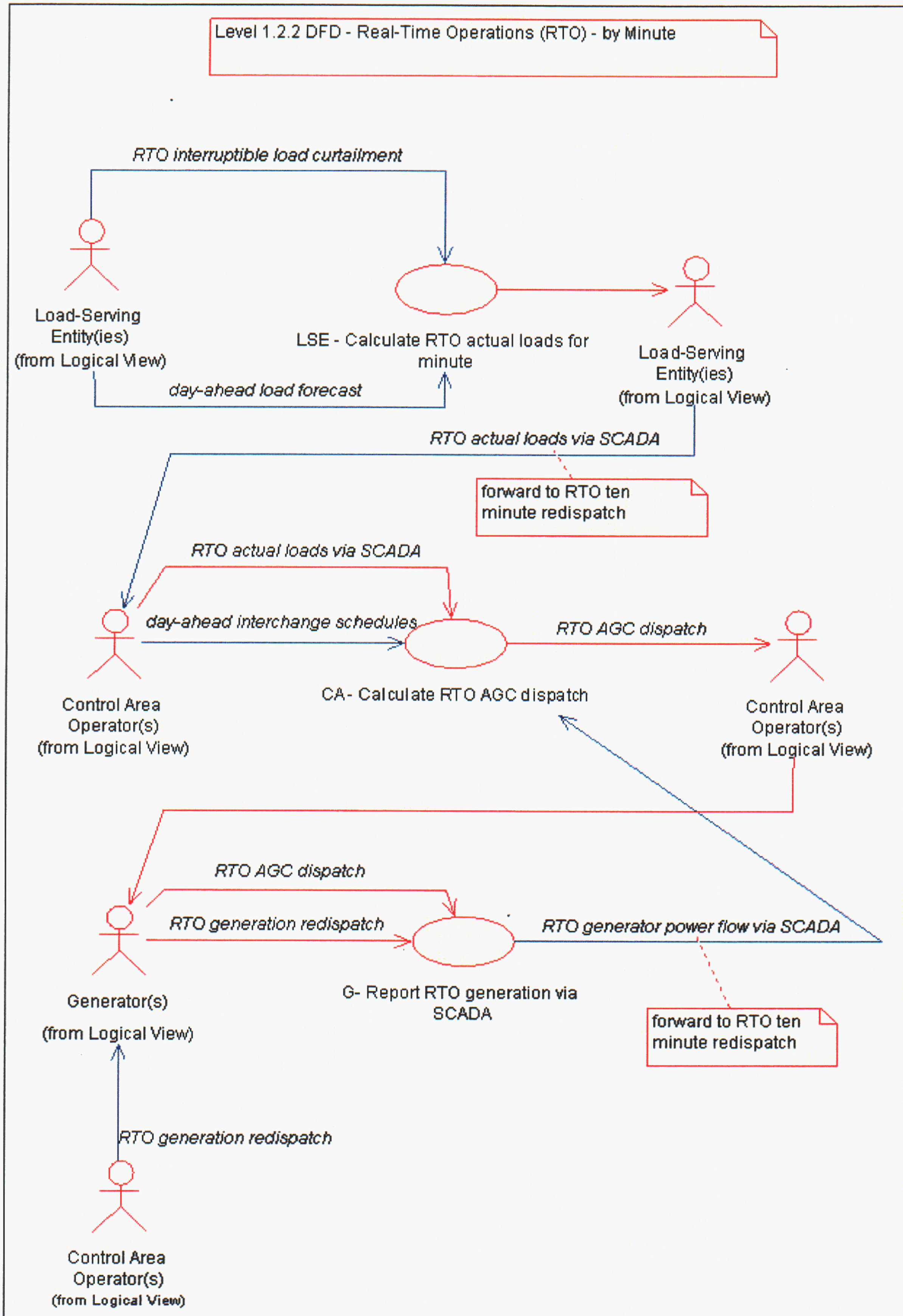


Figure 28 - Real-Time Operation by Minute Data Flow Diagram (Level 1.2.2)

3.1.5.3.2 CA - **Calculate RTO AGC dispatch**

Requirement #: IMGC.0054.002	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 09/13/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Adjust generation for each generator unit operating in AGC mode to balance the actual load with the generation dispatch from the last minute.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO actual loads via SCADA, day-ahead interchange schedules
Algorithm:

- Calculate the generation-load imbalance as scheduled generation minus NIS minus actual loads for each bus in the Control Area.
- The AGC dispatch for each generator unit operating in AGC mode is proportional to the scheduled generation for that unit.
- AGC dispatch can be either positive which increases generation or negative which decreases generation and is performed at one-minute intervals.

Output: RTO AGC dispatch

3.1.5.3.3 G - **Report RTO generation via SCADA**

Requirement #: IMGC.0057.001	Area:	Status:	Classification:	Surety rating: ☒ None
Date introduced: 06/21/2000	☒ ACE	☒ Draft	☐ UCI	☐ Moderate
Date of last change: 06/21/2000	☐ IA	☐ Accepted	☒ None	☐ High

Used for: Report actual generation from each generator unit based on dispatch from the Control Area from the previous minute.

Bounds/Range: N/A

Active during: RTO Phase

Source(s): N/A

Format: N/A

Methods:

Input: RTO AGC dispatch, RTO generation redispatch
Algorithm:

- Echo the AGC dispatch or generation redispatch for each generator unit to the Control Area that dispatches the unit.

Output: RTO generator power flow via SCADA

Appendix A - Shorthand Requirements Table

Requirement #	Page #	Type	Attributes or Method	Shorthand of requirement
IMGC.0001	38	Grid Model	----	classes
IMGC.0002	42	""	SC - Attributes	day-ahead power flow results
IMGC.0004	42	""	""	RTO-ten-minute power flow results
IMGC.0005	44	""	CA - Attributes	day-ahead native schedules
IMGC.0006	44	""	""	day-ahead regulation schedules
IMGC.0007	44	""	""	day-ahead contingency reserve schedules
IMGC.0009	45	""	""	scheduling token
IMGC.0010	45	""	""	day-ahead interchange schedules
IMGC.0011	45	""	""	day-ahead insufficient resource warning
IMGC.0013	46	""	""	RTO generation redispatch
IMGC.0016	46	""	""	RTO AGC dispatch
IMGC.0018	46	""	""	RTO ACE
IMGC.0020	46	""	""	RTO dispatch interruptible load curtailment
IMGC.0021	47	""	TSP - Attributes	day-ahead operating limit violations
IMGC.0022	47	""	""	RTO-ten minute operating limit violations
IMGC.0023	48	""	Grid - Attributes	daily load profile
IMGC.0024	50	""	""	interruptible loads
IMGC.0025	50	""	""	transmission grid model
IMGC.0026	54	""	""	reference parameters for generation sources
IMGC.0027	57	""	Generator - Attributes	day-ahead generation plan
IMGC.0028	59	""	""	RTO generator power flow via SCADA
IMGC.0032	59	"	LSE - Attributes	day-ahead load forecast
IMGC.0033	60	""	""	day-ahead interruptible load forecast
IMGC.0035	60	""	""	RTO actual loads via SCADA
IMGC.0037	64	""	DA - Method	LSE - **Create day-ahead load forecast**

IMGC.0038	64	""	""	G - **Plan day-ahead generation availability**
IMGC.0039	64	""	""	LSE - **Create day-ahead interruptible load forecast**
IMGC.0040	65	""	""	CA- **Establish day-ahead native schedules**
IMGC.0041	65	""	""	CA - **Establish day-ahead interchange schedules**
IMGC.0043	66	""	""	SC - **Calculate day-ahead Power flow analysis**
IMGC.0044	68	""	""	CA - **Establish day-ahead IOS schedules**
IMGC.0045	68	""	""	TSP - **Detect day-ahead operating limit violations**
IMGC.0049	72	""	""	SC - Calculate RTO power flow analysis
IMGC.0050	73	""	""	TSP - **Detect RTO operating limit violations**
IMGC.0051	75	""	RTO-M-Method	LSE - **Calculate RTO actual loads for minute**
IMGC.0054	77	""	""	CA - **Calculate RTO AGC dispatch**
IMGC.0055	73	"'	""	CA - **Calculate RTO generation dispatch**
IMGC.0057	77	""	""	G - **Report RTO generation via SCADA**
IMGC.0058	38	""	----	Generators and configuration
IMGC.0059	39	""	----	Load-Serving Entities and configuration
IMGC.0060	39	""	----	buses, bus loads, and configuration
IMGC.0061	42	""	SC - Attribute	RTO hourly inadvertent interchange
IMGC.0062	72	""	SC - Method	SC - **Calculate RTO inadvertent interchange**
IMGC.0063	73	""	""	SC - **Report RTO hourly inadvertent interchange**
IMGC.0064	43	""	SC - Attribute	RTO inadvertent interchange
IMGC.0065	60	""	LSE - Attribute	RTO interruptible load curtailment
IMGC.0066	74	""	CA - Method	CA - **Calculate RTO ACE**
IMGC.0067	74	""	LSE - Method	LSE - **Implement RTO interruptible load curtailment**

Appendix B - Deleted Requirements Table

Requirement Number	Requirement Description	Reason Deleted	Date Deleted
IMGC-0003	**Security Coordinator Attribute -** voltage at each substation	*This requirement is included* in IMGC.0002	7/28/00
IMGC-0029	**Generator Attribute -** RTO generator reactive power flow on SCADA	This requirement is included in IMGC.0028	""
IMGC-0030	**Generator Attribute -** RTO generator power output	This requirement is included in IMGC.0028	""
IMGC-0031	**Generator Attribute -** RTO generator reactive power output	This requirement is included in IMGC.0028	""
IMCG-0012	**Control Area Operator Attribute** – notification of day-ahead operating-limit violations	This requirement is included in IMGC.0021	""
IMGC-0008	**Control Area Operator Attribute -** day-ahead reactive power supply schedules	Reactive power removed from requirements	9/12/00
IMGC-0014	**Control Area Operator Attribute -** RTO dispatched *regulation and reactive power supply*	""	""
IMGC-0015	**Control Area Operator Attribute -** RTO dispatched contingency reserve	""	""
IMGC-0017	**Control Area Operator Attribute -** RTO-hourly insufficient resource warning	""	""
IMGC-0019	**Control Area Operator Attribute -** AGC commands	""	""
IMGC-0034	**Load-Serving Entity Attribute -** RTO SCADA	""	""
IMGC-0036	**Load-Serving Entity Attribute -** RTO load forecast	""	""
IMGC-0042	**Control Area Operator Method -** CA - Initiate day-ahead transmission assessment	""	""
IMGC-0046	**Control Area Operator Method -** CA- Coordinate day-ahead transmission assessment	""	""
IMGC-0047	**Load-Serving Entity Method -** LSE - Calculate RTO actual loads for top of hour via SCADA	""	""
IMGC-0048	**Control Area Operator Method -** CA - Initiate RTO schedules for new hour	""	""
IMGC-0052	**Control Area Operator Method -** CA - Calculate RTO generation via SCADA	""	""
IMGC-0053	**Load Serving Entity Method -** LSE - Implement *RTO interruptible load curtailment*	""	""
IMGC-0056	**Generator Method -** Deploy RTO regulation and reactive power supply	""	""

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1	0784	Douglas Smathers	06512
1	0455	Stephen Goldsmith	06517
1	0455	Laurence Phillips	06517
1	0455	Reynolds Tamashiro	06517
1	9018	Central Technical Files	8945-1
2	0899	Technical Library	9616
1	0612	Rev. & Approval Desk, For DOE/OSTI	9612